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CP-201200518
TXX-12084

Ref: 10 CFR 50.90
File # 236

October 2, 2012

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

SUBJECT: COMANCHE PEAK NUCLEAR POWER PLANT (CPNPP) DOCKET NOS. 50-445 AND 50-446, LICENSE AMENDMENT REQUEST (LAR) 12-004, REVISION TO TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES - OPERATING," FOR TWO, 14-DAY COMPLETION TIMES FOR OFFSITE CIRCUITS

REFERENCE: Pre-application Meeting Between the Nuclear Regulatory Commission and Luminant Generation Company LLC to Discuss the Future Request for Two, One-time, 14-Day Completion Times License Amendment Request to Technical Specification 3.8.1, "AC Sources - Operating," (TAC NOS. ME1739 and ME1740), Dated June 26, 2012.

Dear Sir or Madam:

Pursuant to 10CFR50.90, Luminant Generation Company LLC (Luminant Power) hereby requests an amendment to the Comanche Peak Nuclear Power Plant (CPNPP), Unit 1 Operating License (NPF-87) and CPNPP Unit 2 Operating License (NPF-89) by incorporating the attached change into the CPNPP Unit 1 and 2 Technical Specifications (TS). This change request applies to both Units.

On June 26, 2012, Luminant Power met with the Nuclear Regulatory Commission to discuss a proposed change to plant TS in the Reference above. The proposed change will revise TS 3.8.1 entitled "AC Sources - Operating" to extend, on a one-time basis, two allowable Completion Times (CTs) of Required Action A.3 for one inoperable offsite circuit, from 72 hours to 14 days. This change is only applicable to startup transformer (ST) XST1 and will expire on March 31, 2014. This change is needed to allow sufficient time to 1) modify the XST1 138kV tower to add disconnects for new alternate ST XST1A and replace existing disconnects for XST1 and 2) to make final terminations to facilitate connection of ST XST1 or alternate ST XST1A to the 1E buses. After completion of this modification, if XST1 should require maintenance or repair or if failure occurs, then the alternate ST XST1A can be aligned to the 1E buses well within the current CT of 72 hours.

Luminant Power's justification for this change to TS 3.8.1 Required Action A.3 CT is based upon the risk informed, deterministic evaluation presented in Attachment 1 to this letter. The change is consistent with the guidance in Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications" (References 8.1 and 8.2, respectively).

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Attachment 1 provides a detailed description of the proposed change, a technical analysis of the proposed change, Luminant Power's determination that the proposed change does not involve a significant hazard consideration, a regulatory analysis of the proposed change, and an environmental evaluation. Attachment 2 provides the affected TS page marked-up to reflect the proposed change. Attachment 3 provides the proposed changes to the TS Bases for information only. These changes will be processed per CPNPP site procedures.

Attachment 4 provides the retyped TS page which incorporates the requested change. Attachment 5 provides retyped TS Bases pages which incorporate the proposed changes for information only. Attachment 6 provides marked-up pages of the Final Safety Analysis Report (FSAR) (for information only) which reflect the proposed changes to the FSAR.

Attachment 7 contains new commitments which will be completed or incorporated in the CPNPP Licensing Basis as noted. The commitment number is used by Luminant Power for the internal tracking of CPNPP commitments.

Luminant Power requests approval of the proposed License Amendment by September 30, 2013, to be implemented within 120 days of the issuance of the license amendment. The plant does not require this amendment to allow continued safe full power operation although approval is required to support a plant modification which will facilitate future connection of either the startup transformer XST1 or an alternate ST XST1A to the 1E buses within the current TS CT of 72 hours.

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

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

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

Executed on October 2, 2012.

Sincerely,

Luminant Generation Company, LLC

Rafael Flores

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

TJEW

Attachments
1. Description and Assessment
2. Proposed Technical Specifications Change
3. Proposed Technical Specifications Bases Change (for information)
4. Retyped Technical Specifications Pages
5. Retyped Technical Specification Bases Pages (for information)
6. Proposed FSAR change (for information)
7. Summary of Regulatory Commitments

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ATTACHMENT 1 to TXX-12084

DESCRIPTION AND ASSESSMENT

LICENSEE'S EVALUATION

1.0 DESCRIPTION

By this letter, Luminant Generation Company LLC (Luminant Power) requests an amendment to the Comanche Peak Nuclear Power Plant (CPNPP), Unit 1 Operating License (NPF-87) and Unit 2 Operating License (NPF-89) by incorporating the attached change into the Comanche Peak Unit 1 and 2 Technical Specifications (TS). Proposed change license amendment request (LAR) 12-004 is a request to revise TS 3.8.1, "AC Sources - Operating" to revise the OR statement to the Completion Time (CT) of Required Action A.3. The statement is applicable only to startup transformer (ST) XST1, expires on March 31, 2014, and will allow, on a one-time basis, two extensions of the CT from 72 hours to 14 days.

Proposed Final Safety Analysis Report (FSAR) (Reference 8.3) changes, as discussed in Section 2 below, are included in Attachment 6 for information only.

2.0 PROPOSED CHANGE

The proposed change is summarized below and shown in Attachment 2.

The proposed change would revise Technical Specifications (TS) 3.8.1, "AC Sources - Operating," OR statement to the Completion Time (CT) of Required Action A.3 to allow two, one-time outages on XST1 to complete a plant modification to be completed by March 31, 2014. The two extended CTs will allow sufficient time to 1) modify the XST1 138kV tower to add disconnects for new alternate startup transformer (ST) XST1A and replace existing disconnects for XST1 and 2) to make final terminations to facilitate connection of ST XST1 or alternate ST XST1A to the 1E buses. After completion of this modification, if XST1 should require maintenance or repair or if failure occurs, then the alternate ST XST1A can be aligned to the 1E buses well within the current TS CT of 72 hours.

For information only, this license amendment request 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.

The proposed changes in Chapters 8 and 9 of the Final Safety Analysis Report (FSAR) (Reference 8.3) (Attachment 6) reflect ST XST1, new alternate ST XST1A, new 138kV tower disconnect switches, firewall, and the installation of new cable buses and transfer panels. The FSAR Table and Figures not shown in the Attachment, but which will also be updated, are Table 8.3-3 and Figures 1.2-1, 8.2-1, 8.2-4, 8.2-7, 8.2-9, and 8.2-11.

3.0 BACKGROUND

3.1 Current Plant Design

The 138 kilo volt (kV) switchyard and 345kV switchyard are supplied from nine transmissions lines, two lines to the 138kV switchyard and seven to the 345kV switchyard. The 138kV switchyard is physically and electrically independent of the 345kV switchyard. The 345kV and the 138kV switchyards each consist of a two bus arrangement having one breaker per transmission circuit. Transmission circuits terminate in individual positions on alternate buses in the switchyards. Power can be supplied to each switchyard from any of their respective transmission circuits. The plant switchyards and transmission line connections are shown in Final Safety Analysis Report (FSAR) Figure 8.2-1.

Two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either Unit. The preferred source to Unit 1 is the 345kV offsite supply from the Comanche Peak Nuclear Power Plant (CPNPP) 345kV switchyard and the startup transformer (ST), XST2 or spare ST, XST2A; the preferred source to Unit 2 is the 138kV offsite supply from the CPNPP 138kV switchyard through the ST, XST1. The preferred power sources supply power to the 6.9kV 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. In the event one ST (e.g., XST1, a preferred source) becomes unavailable to its normally fed 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.

The STs (XST1 and XST2) and spare ST XST2A are physically located in the protected area near the Turbine Building (TB) and not in the switchyards. The switchyards are approximately 600 feet due west of the TB. XST1 is connected to the 138kV switchyard by an overhead line, while XST2 and the spare startup transformer XST2A are connected to the 345kV switchyard by a common overhead line.

Spare ST, XST2A, is in a dedicated location under the 345kV line to XST2 (refer to FSAR Figure 8.2-1) to serve as a replacement of XST2. Cable buses from secondary X and Y windings of XST2 and XTS2A are connected to two 6.9kV transfer panels to provide 345kV offsite power to Units 1 and 2 safety related buses. These transfer panels allow transfer of 345kV offsite power source for safety related buses from XST2 to XST2A and vice verse. This spare transformer, XST2A, may be physically relocated to a dedicated location near XST1, to serve as a replacement of XST1.

Currently, if XST1 requires maintenance that would exceed 72 hours, or if XST1 fails, it would take about 18 to 21 days to replace XST1 with the spare ST XST2A. The timing is dependent on the mobilization/availability of heavy haulers, extent of transformer damage, and the availability of needed equipment and personnel to perform the work. Since each ST provides one of the two required offsite AC sources for each CPNPP Unit, an outage of XST1 for greater than the current Completion Time (CT) of 72 hours would require that both Units be shutdown to Mode 5.

3.2 Proposed Plant Design Modification

This proposed amendment is similar to one previously approved by the Nuclear Regulatory Commission (NRC) on October 29, 2010 (ML103190632), that extended, on a one-time basis, the allowable CT of Required Action A.3 for the 345kV inoperable offsite circuit, from 72 hours to 14 days. This change was only applicable to ST XST2 and expired on March 1, 2011 and allowed sufficient time to make final terminations to facilitate connection of either XST2 or the spare ST XST2A to the Class 1E buses. The entire sequence of activities was projected to require approximately 11 days and 13 hours to complete which fit well within the requested 14-day extended CT. The actual time required to complete the plant modification was 7 days, 21 hours, and 16 minutes.

The main difference between the previous license amendment approved in 2010 and this license amendment request is that there was an installed spare transformer XST2A under the 345kV line that fed XST2 and the 1E buses but had to be relocated to serve as a replacement for XST1 as described in Section 3.1. In the present situation, there is no installed alternate transformer for XST1 thus additional provisions must be made to allow for the installation of a new transformer. Consequently, this requested amendment will require three primary scopes of work:

- 14-day CT is required to complete the 138kV work,
- Perform the necessary preparation, installing and testing of the new alternate ST, and
- 14-day CT is required to complete the 6.9kV work.

The proposed change will revise Technical Specifications (TS) 3.8.1 entitled "AC Sources - Operating" to extend, on a one-time basis, two allowable CTs of Required Action A.3 for one inoperable offsite circuit, from 72 hours to 14 days. This change is only applicable to ST XST1 and will expire on March 31, 2014. The proposed change is needed to allow sufficient time to 1) modify the XST1 138kV tower to add disconnects for new alternate ST XST1A and replace existing disconnects for XST1 and 2) to make final terminations to facilitate connection of ST XST1 or the alternate ST XST1A to the 6.9kV 1E buses within the current TS CT of 72 hours.

Most of the work for this modification (e.g., XST1A 6.9kV cables pulls) will occur prior to the 14-day CTs when XST1 and XST2 are energized and while both CPNPP Units continue power operations in Mode 1.

For the first scope of work, a 14-day CT is needed to modify the 138kV tower for XST1 to support the weight of the new disconnect switches for a new alternate ST and replacement of the old existing disconnect switches for XST1. Specifically, the existing disconnect switches are obsolete, there are no spare parts, and they are difficult to adjust. Completing the 138kV tower work will require that XST1 be removed from service (i.e., open the bus tie breakers in the 138kV switchyard and disconnected from the 1E buses). Once the 138kV tower work is completed, transformer XST1 will be restored and the offsite source will again be operable. The entire sequence of activities to complete the first scope of work is projected to require approximately 11.5 days. Table 1, provides a more detailed list of planned maintenance activities and their durations.

For the second scope of work, no extended CT will be required for the new alternate ST XST1A connections, testing some of the protection scheme, installation of the bushings and coolers and oil-fill. A 72-hour TS CT may be entered to set the transformer on its pad and connect to the 138kV disconnects in order to charge the transformer unloaded for 24 hours. The alternate ST will then be tested to ensure it was not damaged during delivery while isolated from the 6.9kV bus. The installation of the new alternate ST will include a three-hour fire wall that will be constructed between XST1 and the new alternate ST XST1A in addition to an automatic fire suppression water system for the new alternate ST. The times in Table 2 are approximate and some activities will occur in parallel for a total period of 52 days.

Table 1. 138kV Tower Scheduled Work Dates

Maintenance Activity	Approximate Time (Days)
Enter Time Critical LCO and Hang Clearances and Install Grounds *	0.5
Disconnect XST1 and Remove Equipment on From Dead End Structure	1.5
Make Changes to Dead End Structure	0.5
Install New Steel on Dead End Structure	1.0
Install Air Switch for XST1	0.5
Install Air Switch for XST1A	0.5
Install Insulators, Lightning Arrestors, Coupling Capacitors Voltage Transformers, Carrier Line Equipment	1.0
Install Conduit, Pull Cables, Terminate Wires	1.0
Connect Bus to XST1	1.0
Check and Test the Control, Instrument and Protection Circuits	2.0
Remove Grounds and Pull Clearances	0.5
Energize 138kV and Perform Checks	0.5
Energize the 6.9kV 1E Buses from XST1 and Perform Checks	1.0
Exit LCO**	**11.5**
*** Enter 14-day CT **Exit 14-day CT**	

Table 2. XST1A Transformer Movement, Installation, Oil fill and Process, Test and Checks

Maintenance Activity	Approximate Time (Days)
Perform XST1A Preparatory Work	
Move XST1A onto the Permanent Pad	5.0
Assemble the XST1A Transformer	10.0
Fill Transformer with Oil and Process	5.0
Connect XST1A to the 138kV Bus	5.0
Install Transformer Fire Suppression	5.0
Perform Checks and Tests	5.0
Energize XST1A Unloaded	2.0
Complete the 6.9V Cable Connections to XST1A	10.0
Perform XST1A Control, Instrument and Protection Circuit Checks	5.0
Complete the XST1A Installation	**52.0**

For the third scope of work, a second 14-day CT will require XST1 be out-of-service for greater than 72 hours but less or equal to 14 days in order to install the transfer panels, terminate the XST1 and XST1A 6.9kV cables in the transfer panels, and terminate the cables on XST1A. Inside the transfer panels, there are three individual bus bars, one for the 1E bus cables, one for XST1 cables, and one for the alternate ST cables. The transfer panels have removable links that can connect to a ST and the 1E bus such that only one ST can be connected to the 1E buses at any given time. Once the 6.9kV work is completed, ST XST1 will be restored and the offsite source will again be operable.

The entire sequence of activities to complete this third scope of work is conservatively projected to require approximately 12 days. However, a similar modification has been accomplished for XST2 and XST2A and completed in 7 days, 21 hours, and 16 minutes, well within the projected time of 11 days and 13 hours and much less than the requested CT of 14 days. Table 3, provides a list of planned maintenance activities and their approximate durations.

Table 3. 6.9kV Connections Including Final Checks/Test for XST1A Scheduled Work Dates

Maintenance Activity	Approximate Time (Days)
Enter LCO Place Clearance and Grounds*	0.25
Shutdown XST1 Open Box to De-terminate Cables	0.5
Remove Tray, Identify Cables and Cut/Pull Back Cables	1.5
Install Transfer Panels, Modify Cable Trays	3.0
Pull in Cables, Install Stress Cones and Terminate Cables	3.5
Terminate Cables at XST1 and Close Boxes	1.0
Verify Link Placement and Close Boxes	0.25
Remove Clearance and Grounds	0.25
Energize and Test XST1A	1.0
Shutdown XST1A, Change Links and Energize XST1	1.0
Exit LCO**	**12.0**
*** Enter 14-day CT **Exit 14-day CT**	

3.3 Post-Modification Plant Design

Once the modification to the plant is complete and XST1 needs maintenance or if XST1 fails, the alternate ST XST1A can be connected to the safety buses to restore the 138kV offsite source within the current TS CT of 72 hours. After maintenance or repair on XST1 is completed, XST1 may be put back in-service. Therefore, XST1A will be a dedicated alternate for XST1 and XST2A will be a dedicated alternate for XST2.

3.4 FSAR References

Related background in the CPNPP FSAR (Reference 8.3) is found primarily in Section 1A(B), Section 8, and 9.5.1.5.6.

As described above, the proposed change will revise the OR statement of the CT of TS 3.8.1, "AC Sources - Operating" Required Action A.3. The statement will allow, on a one-time basis, two extensions of Required Action A.3 CT from 72 hours to 14 days for an outage of ST XST1 to 1) modify the XST1 138kV tower to add disconnects for a new alternate ST and replace the existing disconnects for XST1 and 2) to make final terminations to facilitate connection of startup transformer (ST) XST1 or a alternate startup transformer to the 1E buses within the current TS CT of 72 hours.

4.0 TECHNICAL ANAYLYSES

The proposed change has been evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth is maintained, and that any increases in core damage frequency (CDF) and large early release frequency (LERF) are small,

consistent with the United States Nuclear Regulatory Commission (NRC) Safety Goal Policy Statement (Reference 8.4), and within the acceptance criteria 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," (Reference 8.1) and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," (Reference 8.2). "Conformance with Nuclear Regulatory Commission (NRC) General Design Criteria," (GDC) Section 3.1 of the Final Safety Analysis Report (FSAR) (Reference 8.3) provides the basis for concluding that the station fully satisfies and complies with the GDC in Appendix A to 10 Code of Federal Regulations (CFR) Part 50. These proposed changes do not affect the basis for this conclusion and do not affect compliance with the GDC.

Four elements provide the basis for the requested Technical Specifications (TS) change and provide a high degree of assurance of the capability to provide power to the safety related 6.9 kilo volt (kV) alternating current (AC) Engineered Safety Features (ESF) buses during the two, one-time, 14-day Completion Times (CTs) (allowed outage time (AOT) or CT as used in the Improved Standard Technical Specifications). The four main elements are (1) traditional engineering analyses, (2) an evaluation of the adequacy of the Comanche Peak Nuclear Power Plant (CPNPP) Probability Risk Assessment (PRA) and a risk assessment that shows an acceptable increase in risk (Tier 1), (3) avoidance of risk-significant plant configurations (Tier 2), and (4) continued implementation of a Configuration Risk Management Program (CRMP) during the two, one-time, 14-day extended CTs (Tier 3).

4.1 Deterministic Evaluation

Offsite Power

The Oncor (Transmission Owner (TO)) transmission system serves as the main outlet and source of offsite power for CPNPP. Connection of the station outputs to the system is achieved via seven 345kV overhead lines to the 345kV switchyard as. The 345kV system forms the backbone of the TO transmission system, it provides a highly reliable source of continuous power for plant shutdown. Another reliable source is the 138kV network via two 138kV lines connecting to the 138kV switchyard. Upon loss of all offsite AC power, station standby power sources, consisting of four diesel generators (two per Unit) are provided to satisfy the loading requirements of the AC safety-related loads. System redundancy precludes loss of all onsite power as a result of any single failure, and specifically, CPNPP has never had a loss of all offsite power in the life of the plant.

Two separate and physically independent startup transformers (STs) (XST1 or XST2) provide startup, preferred and alternate shutdown power to the safety-related auxiliaries of the Units on an immediate basis. One transformer is connected to the 345kV switchyard while the second transformer is connected to the 138kV switchyard; these transformers are connected to the safety-related 6900V auxiliary bus systems and, as such, provide two independent means of supplying the safety-related equipment from the offsite power system without relying on the main generator. If one ST is out-of-service the operating ST has the capacity and capability to supply the required safety related loads of both Units.

Two station service transformers (1ST and 2ST) provide power to the non-safety-related auxiliaries. These transformers are connected to the 345kV switchyard. One transformer is connected to the non-safety-related 6900V auxiliary buses of one Unit while the second transformer is connected to the non-safety-related 6900V buses of the other Unit.

CPNPP has a robust design with the desired defense-in-depth design features (i.e., the ability to mitigate design basis accidents when a ST is out-of-service). Specifically, offsite and onsite power systems are diverse and redundant and meet regulatory requirements of GDC 17. While XST1 is out-of-service during the plant modification outages, XST2 has the capacity and capability to supply the required safety related loads of both Units.

Oncor Transmission Planning (TO) performs yearly assessments of grid reliability for CPNPP. The assessment consists of voltage and stability studies. System stability studies are in accordance with Electric Reliability Council of Texas (ERCOT) requirements whenever Oncor anticipates that a new study could be expected to produce results significantly different from prior studies. ERCOT is the Reliability Coordinator (as certified by the North American Electric Reliability Corporation (NERC)) and the Independent System Operator (as certified by the Public Utility Commission of Texas (PUCT)) for the ERCOT Region.

The 2012 voltage study consisted of the steady-state evaluation of specified contingencies that would impact the CPNPP voltage, in accordance with CPNPP Station Administration Manual STA-629, "Switchyard Control and Transmission Grid Interface," (Reference 8.5). STA-629 defines the CPNPP Switchyard work control process, the NERC Reliability Standard NUC-001, "Nuclear Plant Interface Requirements" (NPIRs), as mutually agreed by Luminant Generation Company LLC and Oncor Electric Delivery Company LLC (TO), and TO's obligations with respect to the NPIRs, in accordance with the requirements of the Generation Interconnection Agreement and NUC-001. The 2012 stability study consisted of an evaluation of the risk of losing offsite power to CPNPP as a result of system instability following sudden loss of system generation.

The voltage study results showed that the 345kV voltage supply to XST2 was maintained within the target maximum and minimum voltages of 361kV and 340kV, respectively and the 138kV voltage supply to XST1 was maintained within the target maximum and minimum voltages of 144kV and 135kV, respectively.

The TO Transmission Planning Procedures list the following requirements for the maintenance of offsite power to CPNPP following sudden loss of system generation:

- The loss of both CPNPP Units shall not result in loss of offsite power to CPNPP.
- The loss of the largest power plant in the ERCOT system shall not result in loss of offsite power to CPNPP.
- The loss of the largest power plant connected to the Transmission Service Provided shall not result in loss of offsite power to CPNPP.
- The loss of the largest capacity experienced during past disturbances on the ERCOT system shall not result in loss of offsite power to CPNPP.

It is evident from the 2012 stability studies that loss of one or both of the nuclear Units will not cause the loss of offsite power or auxiliary power to the station. In addition, the transmission system remains stable for all disturbances near CPNPP which are cleared by primary or backup relaying. CPNPP's Operations Department will contact the Transmission Operator (Transmission Grid Controller) once per day during a 14-day Completion Time to ensure no problems exist in the transmission lines feeding CPNPP switchyards or their associated switchyards that would cause post trip switchyard voltages to exceed the voltages required by STA-629.

Onsite Power

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

Two independent and redundant 6900V Class 1E buses are provided for each Unit, each capable of supplying the required safety-related loads to safely shut down the Unit following a design basis accident (DBA). The standby AC Power System is an independent, onsite, automatically starting system designed to furnish reliable and adequate power for Class 1E loads to ensure safe plant shutdown and standby when preferred and alternate power sources are not available.

Redundant safety-related loads are divided between trains A and B so that loss of either train does not impair fulfillment of the minimum shutdown safety requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains. Electrical separation of redundant trains is maintained through all voltage levels, including direct current (DC) and instrumentation.

During a loss of coolant accident (LOCA), the EDGs are required to start, whether offsite power is available or not. Additionally, failure of a single active component or train associated with one EDG must not result in the inability of the redundant EDG to provide emergency standby power.

The EDGs are required to cope with Station Blackout (SBO) to satisfy the requirements of RG 1.155 "Station Blackout" (Reference 8.6). For the SBO analysis, only one Unit at the CPNPP site is assumed to be in a station blackout condition. The other Unit is assumed to have one emergency diesel generator available.

The diesel generator sets are required to start on receipt of any of the following signals:

a. Safety Injection Actuation Signal - Emergency Start
b. Undervoltage on Respective Emergency Bus - Emergency Start
c. Normal or Emergency Manual Start

Automatic starting signals shall override all other operating modes and return the EDG unit to automatic control unless the unit has been placed in a manual non-operating mode for maintenance or repair.

Station Blackout

CPNPP compliance with the Station Blackout Rule, 10CFR50.63, has been performed in accordance with the guidelines contained in Regulatory Guide 1.155 (Reference 8.6) and NUMARC 87-00 (Reference 8.7). In accordance with those References, CPNPP is not required under 10 CFR50.63 to consider simultaneous loss of both offsite power (LOOP) sources and both EDGs to both Units. CPNPP compliance is based on simultaneous LOOP at both Units, the non-mechanistic unavailability of both EDGs in one Unit, (i.e., the blackout Unit) and the availability of one of two EDGs in the other, "non-blackout" Unit.

CPNPP does not utilize an "alternate AC source," as defined in References 8.7 and 8.8, for purposes of compliance with 10CFR50.63. The single EDG in the "non-black-out" Unit is credited for powering specified ventilation cooling systems, e.g., control room ventilation, in accordance with the plant design. The compliance analyses for the "blackout Unit" are based on the "AC-Independent" approach detailed in Reference 8.7. The required coping time for the "blackout Unit" is four (4) hours per Section 3 of Reference 8.7.

EDG reliability was determined using the methodology of Reference 8.7.and is 0.95 for CPNPP. EDG reliability is monitored under the Maintenance Rule Program. Increasing the allowed outage time for ST XST1 has no effect on EDG reliability.

Utilizing the methodology of Reference 8.7, CPNPP has been classified as "AC power Design Characteristic Group" P1. A "P1"site is defined in Reference 8.7 as "...Sites characterized by redundant and independent power sources that are considered less susceptible to loss as a result of plant-centered and weather-initiated events."

The portion of the SBO coping analysis related to the offsite power supply system includes the following in the characterization of CPNPP as a "P1" Offsite Power Design Characteristic Group:

- Susceptibility to LOOP due to extremely severe weather (ESW Group) - Group ESW1 (least susceptible)
- Susceptibility to LOOP due to severe weather (SW Group) - Group SW1 (least susceptible)
- Independence of the offsite power system (I Group) - I1/2

The effect of increasing the CT for ST XST1 has been assessed in Section 4.2 below.

Transformer Health/Reliability Program

The offsite power source (XST2 and XST2A and switchyard equipment) health and reliability are monitored as part of the CPNPP Equipment Reliability Process. This process is defined in CPNPP's Station Administrative Manual STA-748, "Equipment Reliability Process" which implements the guidance outlined in Institute of Nuclear Power Operations' (INPO) AP-913, "Equipment Reliability Process Description." The equipment reliability process directs monitoring of equipment by:

- Daily Monitoring by Responsible Work Organizations such as, Operations, Maintenance and Plant Optimization Center,
- Weekly/Monthly Monitoring of Switchyard Equipment,
- Operating Experience,
- System and Component Health Programs,
- Regulatory Notices,
- Predictive Maintenance,
- Preventive Maintenance/Predictive Maintenance Results, and
- Maintenance Rule.

Individual monitored points for the associated transformers (XST2 and XST2A) are established from American National Standards Institute/Institute of Electrical and Electronics Engineers (ANSI/IEEE) transformer standards, Nuclear Electric Insurance

Limited (NEIL) Loss Control Program, Industry Experience and Manufacturer recommendations. When the performance or monitoring parameters are exceeded the Corrective Action Process is utilized for resolution. Each corrective action item is reviewed by the Management Review Committee for appropriate assignments and level.

The ST XST2 had high capacitance value on the neutral bushing and low side winding bushing leaks which were corrected in August 2012. Completion of the XST2 maintenance outage will have all preventive maintenance (PM) work orders associated with XST2 current. Further, to allow XST2 maintenance to occur, CPNPP implemented reliability improvements to the spare, startup transformer XST2A. Additionally, CPNPP utilized a NRC approved 14-day CT extension which allowed sufficient time to make final terminations to facilitate connection of either XST2 or the spare ST XST2A to the Class 1E buses. These activities will support and maintain the availability of the ST XST2 to remain a reliable offsite power source to meet CPNPP requirements during the two, one-time CT extensions for XST1.

The individual monitoring points for the switchyard equipment are established from NEIL Loss Control Program, Industry Experience and Manufacturer recommendations. The switchyard equipment associated with the offsite power source XST2 are 345kV breakers 7970 and 7980 and associated air disconnect switches 7981/7979 and 7969/7971. If the performance or monitoring parameters are exceeded the Corrective Action Process is utilized for resolution. Each corrective action item is reviewed by the Management Review Committee for appropriate assignments and level. There are no outstanding corrective actions for switchyard equipment associated with the Unit 1 offsite power source.

Breaker 7970 was replaced on December 04, 2010, as an upgrade by the TO. Reliability improvements to the gas system for breaker 7980 have been implemented. Cabling to both 7970 and 7980 has been replaced as part of the TOs overall switchyard reliability improvement plan. The power from XST2 to the Unit 1 safeguard buses is through 6.9kV breakers 1EA1-1 and 1EA2-1. During a one-time, 14-day CT extension, the Unit 2 safeguard buses power will be manually transferred from the primary source (XST1) to the alternate source (XST2). At this time, the Unit 2 safeguards buses will be supplied by XST2 by breakers 2EA1-2 and 2EA2-2. The monitoring of the 6.9kV breaker performance is by surveillance, Operations walkdowns, and PM work orders. If breaker deficiencies are identified, the Corrective Action Process is utilized for resolution. Each corrective action item is reviewed by the Management Review Committee for appropriate assignments and level. Prior to initiation of a one-time, 14-day CT extension, PM task for breakers 1EA1-1, 1EA2-1, 2EA1-1 and 2EA2-2 will be verified as current.

In summary, the equipment associated with CPNPP offsite power has maintained a high degree of reliability and CPNPP has not experienced a loss of offsite power.

Maintenance Plans/Actions (Maintenance Rule) for the STs (XST1, XST2, and XST2A)

The CPNPP Maintenance Rule (MR) Program requires an evaluation be performed when equipment covered by the MR fails to meet the established performance criteria for reliability and availability. Failure of the offsite power sources (XST1, XST2/XST2A) to meet the performance criteria requires a review for determination of 10CFR50.65 (a)(1) actions. These actions would require increased management oversight and establishment of goals to restore the offsite power sources to an acceptable performance level. The

CPNPP offsite power system MR status is (a)(2) with a 24 month rolling average unavailability of 0% through July 2012. On April 22, 2010 CPNPP lost power to XST1 due to bird nesting activities within the base opening of a 138kV tower insulator. This placed the CPNPP offsite power system in MR status (a)(1). Corrective actions following the event sealed off access to the openings at the insulator mounting base. This action removed the ability of bird nesting to impact the tower insulators. A continuing action has been established to perform additional visual inspection of the offsite source transmission lines and transformers during nesting season. This added action helps ensure that alternate bird nesting is not impacting the offsite power sources. Presently, there are no reliability issues identified for XST1, XST2 or XST2A. Maintenance has occurred on XST2 to remove a potential neutral bushing reliability issue. The CPNPP MR status for the offsite power system is not expected to be adversely impacted by application of the two, one-time 14-day CT's implementation because XST2 has proven to be a reliable component and improvement to it 345kV feed further enhances the offsite source to XST2A.

The Need for Two, One-Time 14-Day Completion Times

The preferred plan for the work would utilize the first 14-day CT to make modifications to the 138kV tower as discussed above which will take approximately 11.5 days as detailed in Table 1. Once the work is completed, transformer XST1 would be restored so both offsite sources would again be operable. The next scope of work as described in Table 2 will be preparing XST1A for installation on its pad, installing XST1A, assembling and testing. This scope of work is estimated to take approximately 52 days. The second 14-day CT will be used for the third scope of work, as depicted in Table 3, to install the transfer panels and make final 6.9kV cable terminations in the transfer panels. All three work scopes will take approximately three months to complete. These three work scopes have been logically planned out, sequenced, and separated considering the amount and kind of work performed, the number of diverse work groups performing work in parallel paths, work groups performing both work scopes, the necessary large lifting equipment and trucks, the limited work space in the area, the safety of the workers given the possibility of working under suspended loads, and the health and safety of the public; therefore, two separate 14-day CTs are being requested. However, either 14-day CT can be completed first without affecting the health and safety of the public. As discussed below in Section 4.3, the window of time to invoke the two, one-time 14-day CTs is during the period from September 1st through March 31st when there is a significant reduction in weather risk. The time periods between the three scopes of work largely depend on weather and the actual delivery of the new ST XST1A. However, CPNPP would prefer to complete the three scopes of work as soon as practical considering the safety of plant workers and the health and safety of the public.

To further enhance the safety of the proposed modifications, appropriate just-in-time (JIT) training will be provided to Operations personnel on this TS change as well as the compensatory measures and risk reduction measures to be implemented during these two, one-time, 14-day proposed CTs. The JIT training will include the postulated loss of the operating ST (XST2) to heighten Operations personnel awareness of challenges to the electrical distribution during the modification outages. Additionally, Electrical Support and Meter and Relay crews will be trained on the procedures developed and issued for connection of the alternate ST, XST1A in place of XST1.

Installation of this modification will enhance the plant design by providing the capability to preclude an extended interruption of offsite power in case of failure of, or maintenance on, XST1 that would exceed the current CT of 72 hours. Additionally, this change will improve the long-term reliability of the 138kV offsite circuit by providing connection to the ESF buses through XST1 or the alternate ST. As explained above, performing the work during two, 14-day CTs will provide a safe work environment for personnel safety and will not impact nuclear safety or the health and safety of the public.

Options and Risks with One Unit in a 14-Day CT and Other Unit is in a Refueling Outage

If CPNPP removed one offsite circuit from service for 14 days while one Unit was in a Refueling Outage (RF), TS 3.8.2 "AC Sources - Shutdown" would be satisfied for the RF Unit since only one operable offsite circuit and one operable EDG is required. However, TS 3.8.1, "AC Sources - Operating" requires a Unit in Modes 1 to 4 to have two qualified offsite power circuits and two EDGs; consequently, the operating Unit would not meet the requirements of TS 3.8.1 and must shut down within 72 hours or have an approved NRC license amendment allowing the extended CT.

Further, management and plant employee focus would be split on both 14-day CT work and RF work instead of just one work scope. Moreover, RFs typically take three to four weeks, 24 hours per day to complete. Additionally, the same plant personnel working in the RF will be the same resources needed to complete the 6.9kV work and support the 138kV work as needed while a transmission contract crew will perform most of the 138kV tower work. Therefore, working during a 14-day CT concurrent with a RF would result in a significant reduction of resources and competing priorities.

Also, during RFs the TO works in the switchyards to do line and switchyard maintenance and there is a greater chance for tripping switchyard equipment/lines and thus the possibility to lose the operating ST, XST2, and challenge nuclear safety.

It is undesirable to enter the extended CT for the XST1 transformer with either Unit in a refueling outage/shutdown configuration. During a shutdown, a Unit undergoes continuous configuration changes in reactor coolant system (RCS) inventory, RCS temperature, equipment availability, etc. Also, in shutdown configurations automatic actuation of equipment is more limited and requires Operators to manually diagnose and respond to transient/accident conditions.

Although decay heat level in the reactor would be lower, as compared to operating in Mode 1, variations in reactor coolant system (RCS) inventory, pressure, and temperature result in configurations where time to boil is short (<15 minutes) thus limiting the available time to perform operator actions or other compensatory measures to prevent core boiling/damage. Limited response times are of particular concern given that majority of the prompt mitigating actions for shutdown configurations are manual and may require realignment of various systems. Additionally, as a result of the fluid nature of an outage, various systems relied on for mitigation of an event will be removed from service. This results in plant conditions that would be dependent upon single trains of front line mitigating and support systems.

Major accident/transient scenarios in shutdown configuration remain similar to those at power. While mechanistic LOCAs are less likely, given lower RCS pressure, the potential to inadvertently drain the RCS exists from maintenance or system realignments exist. The

ability to remove decay heat via secondary heat removal may not exist dependent upon the RCS configuration. The time when the RCS is intact and the loops are filled is generally small compared to the entire shutdown duration. Also industry experience has shown that shutdown operations represent a time period of increased likelihood for unanticipated events, compared to at power (Mode 1) operations.

During the times that the reactor core will be offloaded to the spent fuel pool, the CPNPP plant design would isolate the operating Unit's capability to supply cooling and electrical power to the spent fuel pool cooling system following a design basis LOCA. Therefore, the spent fuel pool cooling would be dependent on the outage Unit which most likely is reliant on a single train of supporting equipment. Further the spent fuel pool has limited makeup capabilities and mitigation methods as compared to when the fuel is in the reactor vessel.

Given the complexity of shutdown operations, it is therefore undesirable to reduce the redundancy of offsite power by performing the extended XST1 CT while either Unit is shutdown. Planning the proposed 14-day CTs while both Units are at power provides the ability to control work in a manner that assures redundancy and diversity of mitigation equipment to contend with accident/transient conditions. Considering safety system unavailability during an event and the increased work scope required for a 14-day CT and the RF work scope, human error is more likely to be introduced which could negatively impact nuclear safety, personnel safety, and the health and safety of the public.

Alternate Power Diesel Generators (APDGs)

On October 29, 2010, the NRC previously approved License Amendment Request 09-003 (ML103190632) for XST2, to extend, on a one-time basis, the allowable CT of Required Action A.3 for the inoperable offsite circuit, from 72 hours to 14 days. This change was only applicable to ST XST2 and allowed sufficient time to make final terminations as part of a plant modification to facilitate connection of either XST2 or the alternate ST XST2A to the Class 1E buses. As a defense-in-depth feature concerning this modification, a set of alternate power diesel generators (APDGs) were installed for each Unit to maintain the capability to provide power for one train of ESF equipment needed for safe shutdown and long term cooling of each Unit during the XST2 extended CT to respond to a beyond design basis event (DBE) if loss of XST1 occurs and both EDGs of a Unit fail to start and load as designed. However, the APDGs actually installed in 2010 were rated higher than the ones described in License Amendment Request 09-003 (4275kVA vs. 4200kVA) and in the CPNPP response on May 4, 2012 to the NRC's request for additional information (ML101340121).

These APDGs have not been removed; they remain in the station yard and are designed to be manually connected to a 6.9kV bus. The sequencing of the required loads on the APDGs is also performed manually. The APDG set consist of three diesel generators operating in parallel at 480V, 3 phase, and 60 Hz. Each APDG in a set is rated at 1140kW with outputs connected in parallel for a total capacity of 3420kW. The APDG set is rated at 4275kVA. As part of the APDG package, a 480V/6900V transformer is provided to connect the APDGs to the 6.9kV bus. The transformer may be loaded to 3450kVA; therefore, the APDG load limit is approximately 3450kVA. Each generator of an APDG set has a useable fuel oil tank capacity of 340 gallons (340 gallons is gross 298.8 gallons is useable).

Plant procedure SOP-614A/B "Alternative Power Generator Operations" (Reference 8.8) requires the APDG fuel be replenished every two hours. The APDG consumption rate is approximately 96.7 gallons per hour at 100% power with an approximate run time of 3.08 hours.

The APDGs maintain the same capability as described below during the two XST1 extended CTs to respond to a beyond design basis event if loss of XST2 occurs, both EDGs of a Unit fail to start and load as designed, and at least one EDG starts and loads on the other Unit. If this event were to occur, the APDGs will be manually connected to the affected Unit's 6.9kV safety bus in Modes 3, 4, and 5. Thus, the minimum set of components for one train required to maintain the affected Unit in a safe shutdown condition can be loaded onto the APDG and operating within approximately one hour to maintain the plant in a safe shutdown condition which meets CPNPP's Station Blackout analysis. The components required to be loaded onto a 1E bus to support maintenance of the plant in a safe shutdown condition are described functionally in a plant design basis document (see DBD-ME-026) and emergency response guidelines. The loads identified below represent the Unit-specific (i.e., non-common) loads. These components are the minimum set required to be loaded onto one APDG set to maintain the affected Unit in a safe shutdown condition and provide long term cooling.

Table 4. Load Description and Load in KW

6.9KV LOAD DESCRIPTION	LOAD (KW)
Centrifugal Charging Pump (CCP)	526.03
Component Cooling Water (CCW) Pump	789.42
Station Service Water (SSW) Pump	643.10
480V LOAD DESCRIPTION	**LOAD (KW)**
Containment Recirculating Fan	93.25
Safety Chillers	99.90
Safety Chiller Recirculation Pump	18.24
Emergency Lighting	132.69
Control Rod Drive Mechanism Ventilation (CDRM) Fan	92.44
Instrument Air	183.28
Pressurizer Heater Control Group A	141.40
Battery Chargers and Inverters	110.94
Reactor Makeup Water Pump	4.54
Miscellaneous 480V Loads (Fans, Pumps, Transformers, and Heaters)	116.03
SUBTOTAL	**2951.26**
Plus 2% Losses	59.03
TOTAL	**3010.29**

Each APDG set has adequate capacity and capability to supply power to the necessary equipment for safe shutdown and long term cooling for a Unit.

Prior to installation at CPNPP, the APDG vendor provided formal shop testing of the APDG set. The vendor used test instruments that were calibration certified to measure voltage, current, and frequency, and they reported the test results to CPNPP along with the instrument calibration certifications. At the beginning of the test, the APDG set was allowed to reach normal voltage and frequency prior to switching to the first load. The following load step tests were performed to show load acceptance and removal when all three generators are paralleled:

- 1000kW block load at .8 power factor and let stand for a minute.
- Removal of 1000kW block load at .8 power factor.
- 2000kW block load at .8 power factor and let stand for a minute.
- Removal of 2000kW block load at .8 power factor.
- 2500kW block load at .8 power factor and let stand for a minute.
- Removal of 2500kW block load at .8 power factor.
- 2400kW block load at .8 power factor and add 600kW at 1.0 power factor and let stand for a minute.
- Removal of 3000kW of load.

The test results showed that:

- APDG set is capable of supplying power within 60 seconds of starting.
- The recorded APDG set voltage remains within 480V +/- 20% and frequency remains within 60 Hz +/- 5% during load sequencing, load rejection, or load restart.
- The maximum time to recover voltage to 90% and frequency to 98% of rated values is less than or equal to two seconds.
- While the load on the APDG set is at 3000kW, the APDG set is capable of rejecting a load of 1000 HP (horse power) without generating over-voltages that would damage safety related equipment or tripping on overspeed.
- The APDG set is capable of restarting a 1000 HP motor while maintaining the system load of 3000kW, after the start of the 1000 HP motor.

Plant procedure SOP-614A/B "Alternative Power Generator Operations" (Reference 8.8) directs the Operator to monitor the APDG set parameters (e.g., lube oil, engine coolant, fuel levels, transformer temperature and liquid levels, etc.) on a shiftly basis to ensure the APDG set is ready to start. Once per month the APDG set are started and synced together unloaded to verify there are no problems with the diesels per SOP-614A/B. Additionally, SOP-614A/B directs the operation of the APDGs in Modes 3, 4, 5, and 6. Further, current emergency operating procedures exist that direct Operators to respond to a loss of all AC power, recovery of power without a safety injection signal, and natural circulation cooldown of a Unit. Operators are routinely trained on and have experience in using these procedures. Therefore, if the event above were too occurred, the Operations Shift Manager would declare the affected Unit 1E buses inoperable, direct the connection of the APDG set to a 1E bus and then sequence the appropriate loads onto that bus as directed by the emergency operating procedures. Phase rotation was complete when the APDGs were originally installed in late 2010. Since the APDGs remained connected, no further phase rotation is required unless they are disconnected. Thus, the affected Unit will be safely shutdown and long term cooling will be provided by the APDG.

In this scenario, the APDGs will be connected to the 1E bus only when that Unit has no other source of power; therefore, synchronization of the APDGs to the 1E bus is not applicable in this case.

The APDG set associated with the affected Unit will be able to energize the appropriate buses and the required components can be loaded onto the energized buses within approximately one hour. No consequences on safety limits are expected. The following Table shows the loading sequence of the loads that will be powered by the APDGs.

Table 5. Safe Shutdown Bus Loading Sequence

LOAD	LOAD SEQUENCING NOTES
Station Service Water Pump	These loads will remain aligned to the affected Unit 1E bus in order to energize/start them immediately upon power restoration by the APDG set.
480V Buses (Note 1)	
Battery Chargers	
Instrument and Control Inverters	
Reactor Protection Inverters	
Emergency Lighting	
Direct Current (DC) Loads Shed During DC Load Shedding of Non-Essential Loads	Following Power restoration to the 1E bus by the APDG set, these DC loads will be restored to the DC bus (e.g., loading AC Battery Chargers).
Component Cooling Water (CCP) Pump	These loads will be started following power source restoration as directed by the emergency operating procedures (e.g., APDGs start and energize the 1E bus) to support the plant response and recovery actions (e.g., reduce Reactor Coolant System (RCS) Temperature and Pressure).
Instrument Air Compressor	
Centrifugal Charging Pump (CCP)	
Containment Fan Coolers (Note 2)	
Safety Chiller	
Safety Chiller Recirculation Pump	
Pressurizer (PRZR) Heaters (Note 3)	
Reactor Makeup Water Pump	
Control Rod Drive Mechanism Vent Fans	This load will be started next to assist in Reactor Vessel Head cooling.
Positive Displacement Pump (Note 4)	Finally, these loads will be started to place the RCS in Shutdown Cooling after RCS temperature has been reduced.
Residual Heat Removal (RHR) Pump (Note 5)	

NOTES:

1. Some Unit specific load shedding (e.g., unavailable EDGs) will be performed to reduce loading assumed by the APDGs.
2. One Containment Fan Cooler will be aligned for Containment cooling.
3. Only a specified number of breakers will be closed to allow PRZR Heater capability for control of RCS pressure.
4. To support RHR Pump load, the CCP will be stopped and the Positive Displacement Pump will be started prior to starting the RHR Pump.
5. Secondary heat removal for natural circulation cool down is provided by the TDAFWP prior to placing RHR in shutdown cooling.

The largest motor to be loaded on the APDG is 1000 HP CCW Pump Motor. The vendor test results showed that the APDG set is capable of starting a 1000 HP motor while maintaining the system load of 3000kW, after the start of the 1000 HP motor.
Each Unit Class 1E 6.9kV buses may be connected to the APDG transformer though permanently installed non-Class 1E transfer switch specifically to facilitate the temporary connection of an APDGs set to the selected Class 1E bus. Each APDG set has cables that run in cable trays to the associated transfer switch via a plant owned 480V/6.9kV transformer and the cables will remain de-energized unless such an event as described above occurs.

Class 1E 6.9kV switchgear breakers connected to the transfer switch are normally locked in the disconnect position to assure isolation from non-class 1E transfer switch circuit. These breakers can be manually closed, if required, to provide connection to the APDG. The over-current protection on these breakers is disabled. The protection of the 6.9kV system and APDG circuits when the APDG set is feeding the bus is accomplished as defined below.

- The 480V/6.9kV APDG output transformer is high resistance grounded on the 6.9kV side to assure that the safety related 6.9kV system is not exposed to transient over-voltages and the damage at the point of fault is limited by limiting ground fault current to less than 2A. The transformer grounding system has sensitive ground fault detection with a local ground fault indication and no tripping action.
- The associated cables that feed the Class 1E 6.9kV buses from the APDG transfer switch have sufficient capacity to carry the APDG set limiting load of 3500kW at 0.8 PF.
- The protection provided with the APDG set, or the inherent current limiting feature of the APDG set was reviewed to assure that the duration and magnitude of APDG fault contribution is within the continuous rating of 6.9kV bus.
- The 6.9kV cables from the transformer to the transfer switch provided by CPNPP are sized to carry greater than or equal to 383A and can carry the APDG set loads continuously without being over loaded.
- Postulated electrical faults that could occur at the 6.9kV bus while being fed from the APDG set are assumed to be cleared by protection provided with the APDG set. However, if this protection fails, the magnitude of the fault current could not damage the bus because the APDG set output breakers will trip in one-half cycle if fault current at the bus is 1200A, the continuous rating of the bus.

During outages when the plant is in Mode 5 or 6, the APDG may be used to supply power to either train of the 6.9kV safeguards system. The APDG is used as a backup to supply power in the event that one emergency diesel generator is out-of-service and the remaining operable emergency diesel generator fails to start and load automatically upon a loss of offsite power. The APDG is manually started and connected to the 6.9kV safeguards bus through the load transfer switch and respective bus feed breaker. There are plant procedures governing the use of the APDGs and plant personnel have many years of operating experience using the APDGs during outages and specifically since late 2010 to respond to a beyond design basis event as discussed above. Existing plant procedures describes the steps to operate the APDGs (e.g., startup, operating parameters, alarm responses, troubleshooting, shutdown, pre-run checklist, load testing, refueling, etc.).

Further, within two weeks before entering a 14-day CT, the APDG will be tested to ensure the reliability of the APDG. Additionally, the APDG provided for each Unit will be verified available to provide power to equipment for long term cooling once per shift during the two, 14-day CTs. Training has been provided to all Nuclear Equipment Operators (NEOs) as documented by the training department. New Operators are trained prior to the outages. Prior to the APDGs needing to be available for use, the APDGs are started and synchronized together unloaded on a monthly basis to verify there are no problems with the diesels per SOP-614A/B, "Alternative Power Generator Operations" (Reference 8.8). When the APDGs need to be available for use:

- A shiftly checklist is completed to ensure the APDGs are ready for use per SOP-614,
- At the beginning of shift, briefs designate the three Operators and the roles of each Operator in starting and syncing the APDGs to the required safeguards bus, and
- Procedures are marked up and staged for Operators to start and synchronize the APDGs to the required safeguards bus.

Normal time to provide power from the APDGs to a safeguards bus is approximately one hour. During a 14-day CT, if an APDG becomes unavailable, both Units shall enter Condition C of TS 3.8.1 and start shutting down within 24 hours.

In conclusion, the APDGs have the capacity and capability to provide power for one train of ESF equipment needed for safe shutdown and long term cooling of each Unit during the XST2 extended CT to respond to a beyond design basis event if loss of XST1 occurs and both EDGs of a Unit fail to start and load as designed.

Compliance with NRC Standard Review Plan (SRP) Branch Technical Position (BTP) 8-8

The compliance with BTP 8-8 requirements and CPNPP response is discussed below. Commitment references have been broken up into two groups, one for the 138kV work and the other for the 6.9kV work, respectively. See Attachment 7 for a complete list of commitments.

a. A supplemental power source should be available as a backup to the inoperable EDG or offsite power source, to maintain the defense-in-depth design philosophy of the electrical system to meet its intended safety function.

Response:
The CPNPP design and licensing basis for safe shutdown is hot shutdown. Analyses performed to ensure conformance with BTP Reactor Systems Branch (RSB) 5-1 (Reference 8.3) confirm the ability to achieve cold shutdown in a reasonable period of time following a LOOP with subsequent natural circulation cooldown assuming one Train of safety equipment available.

As detailed in the "Station Blackout" section above, CPNPP compliance with 10 CFR 50.63 is based on a postulated LOOP affecting both Units and the non-mechanistic unavailability of both safety-related EDGs on one of the two Units. A single EDG is assumed available on the non-blackout Unit during such a scenario. The available EDG on the non-blackout Unit is taken credit for fulfillment of control room and uninterruptible power supplies (UPS)/inverter

room ventilation functions. Under those postulated conditions, the blackout Unit has been shown to be fully capable of compliance with 10CRFR 50.63 for the required four hour coping duration. Subsequent beyond design bases assessments performed in consideration of the Fukushima accident verify the effective coping period to be significantly longer.

Additionally, INPO issued Event Report (IER) Level 1(L1) 11-4, "Near-Term Actions to Address the Effects of an Extended Loss of All AC Power in Response to the Fukushima Daiichi Event" (Reference 8.9) to establish actions to improve the margins of safety for loss of AC power events. Specifically, recommendation 1 required, "For all Units, develop methods to maintain (or restore) core cooling, containment integrity, and spent fuel pool inventory using existing installed and portable equipment during an extended loss of electrical AC power event that lasts at least 24 hours." CPNPP reported to INPO that CPNPP can withstand with a station blackout for at least 24 hours, using existing plant equipment and procedures, with a best estimate analysis in accordance with the specified IER L1-11-4 assumptions and bases (Reference 8.10).

CPNPP has provided three (3) APDGs per Unit to provide additional safety margin against postulated loss-of-power events. The three APDGs per Unit operate in parallel as a set providing a combined output of approximately 3420 kW (4275kVA). The APDGs feed a 480 V/6900 V transformer which may be loaded to 3450kVA. Although originally provided and sized for shutdown mode conditions and associated loading, the APDGs provide an additional level of defense-in-depth for "higher" operating modes as well.

During the proposed period of XST1 extended CTs, the APDGs would be available to provide an additional measure of defense-in-depth, beyond that required by the plant design and 10 CFR 50.63, in the unlikely event of a LOOP with concurrent unavailability of both EDGs on either Unit. As was the case for the 10 CFR 50.63 analyses, the non-blackout Unit would be capable to power the aforementioned ventilation loads and shared components, while maintaining the Unit in a safe shutdown condition. The response of the Unit experiencing the total loss of AC power would basically follow the analyses performed for 10 CFR 50.63 compliance; that is to say steam generator water level would be maintained and decay heat removed via the TDAFWP. Manual starting and loading of the APDGs under such circumstances would allow for operation of the following equipment identified in Table 4.

APDG loading is not a time-sensitive activity in the sense the Unit experiencing the total loss of AC power would be in an analyzed condition for the first four hours. This is considered ample time to strip loads from the selected 6.9kV safety bus, start and align the APDGs, repower the selected 6.9kV safety bus, and then to selectively add the loads shown in Table 4 within approximately one hour. Under those postulated conditions, the overall plant condition would be superior to that assumed in the analyses for purposes of 10 CFR 50.63 compliance. The availability of a CCP powered from the APDGs would represent a significant enhancement to plant safety under such conditions.

In the event of postulated failure of the TDAFWP, a MDAFP can be loaded onto the APDGs through manual manipulation of the loads shown in Table 4. For example, the previously operating CCP (-526.03kW) would be shed from the bus and replaced by the positive displacement charging pump (+200kW) to yield a

load of approximately 2684.26kW on the APDGs. Stripping of the non-safety related Containment Recirculation Fan (-93.25kW), instrument air (-183.28kW), and the CRDM Cooling Water Fan (-92.44kW) would yield an approximate APDG load of 2315.29kW and provide sufficient margin to place a MDAFP pump (+611kW) in service. Under such conditions, the approximate load on the APDGs would be 2926kW.

In the unlikely event power were not restored to the blackout Unit and the decision was made to proceed to cold shutdown, manual manipulation of the loads listed in Table 4 would be required in order to support operation of a RHR pump. As in the above scenario, the previously operating CCP (-526.03kW) would be shed from the bus and replaced by the positive displacement charging pump (+200kW) to yield a load of approximately 2684.26kW on the APDGs. Stripping of the non-safety related Containment Recirculation Fan (-93.25kW) and the CRDM Cooling Water Pump (-92.44kW) would yield an approximate APDG load of 2498.57kW and provide sufficient margin to place a RHR pump (+368.2kW) in service. Under such conditions, the approximate load on the APDGs would be 2,866.7 kW. This postulated scenario assumes availability of the TDAFP to support the cooldown (conservatively estimated at between 4-5 hours in duration at a nominal 50 ^{0}F/hour rate and neglecting the depressurization and cooldown effects of postulated RCP seal leakage). Based on the above, it is concluded:

- The APDGs provide the ability to achieve and maintain safe (hot) shutdown for the beyond-design bases consideration of a LOOP coincident with unavailability of both EDGs on a single Unit.
- The APDGs provide the ability to power a MDAFP in the beyond-design bases scenario of a LOOP, coincident with unavailability of both EDGs on a single Unit, and the non-mechanistic unavailability of the TDAFP.
- The ADGs provide the ability to achieve and maintain cold shutdown in the beyond-design bases scenario of a LOOP coincident with unavailability of both EDGs on a single Unit.

b. The supplemental source must have capacity to bring a unit to safe shutdown (cold shutdown) in case of a loss of offsite power (LOOP) concurrent with a single failure during plant operation (Mode 1).

Response:
See response to a. above.

c. The staff has previously granted AOT extensions to those licensees who have installed an alternate alternating current (AAC) power source (i.e., additional diesels, gas or combustion turbines, hydro units, or other power sources) credited for SBO events which can be substituted for an inoperable EDG in the event of a LOOP, provided the power source has enough capacity to carry all LOOP loads to bring the unit to a cold shutdown without any load shedding.

Response:
See response to a. above.

d. The permanent or temporary power source can be either a diesel generator, gas or combustion turbine, or power from nearby hydro units. This source can be credited as a supplemental source, that can be substituted for an inoperable EDG during the period of extended AOT in the event of a LOOP, provided the risk-informed and deterministic evaluation supports the proposed AOT and the power source has enough capacity to carry all LOOP loads to bring the unit to a cold shutdown.

Response:
See response to a. above.

e. For the unit in extended AOT, the licensee must provide a permanent or a temporary power source as a substitute for the EDG in an extended AOT to maintain the same level of defense-in-depth for safe shutdown of the plant.

Response:
See response to a. above.

f. For plants using AAC or supplemental power sources discussed above, the time to make the AAC or supplemental power source available, including accomplishing the cross-connection, should be approximately one hour to enable restoration of battery chargers and control reactor coolant system inventory.

Response:
As described above, the APDG set associated with the affected Unit will be able to energize the appropriate buses and the required components can be loaded onto the energized buses within approximately one hour.

g. The availability of AAC or supplemental power source should be verified within the last 30 days before entering extended AOT by operating or bringing the power source to its rated voltage and frequency for 5 minutes and ensuring all its auxiliary support systems are available or operational.

Response:
Testing of EDGs, APDGs, and turbine driven auxiliary feed water pumps (TDAFWPs) will occur within the two (2) weeks prior to the start of the XST1 CT. (See commitments 4442007 and 4457008.)

h. To support the one-hour time for making this power source available, plants must assess their ability to cope with loss of all AC power for one hour independent of an AAC power source.

Response:
CPNPP has been evaluated to assess compliance with the Station Blackout rule (10CFR50.63) following the guidance provided by RG 1.155 (Reference 8.6). This evaluation determined that both Units are capable of coping with a station blackout (SBO) for 4 hours as AC Independent plants and that no modifications were required. Additionally, the Institute of Nuclear Power Operations (INPO) issued Event Report (IER) Level 1(L1) 11-4, "Near-Term Actions to Address the Effects of an Extended Loss of All AC Power in Response to the Fukushima Daiichi Event" (Reference 8.9) to establish actions to improve the margins of

safety for loss of AC power events. Specifically, recommendation 1 required, "For all Units, develop methods to maintain (or restore) core cooling, containment integrity, and spent fuel pool inventory using existing installed and portable equipment during an extended loss of electrical AC power event that lasts at least 24 hours." CPNPP reported to INPO that CPNPP can cope with a station blackout for at least 24 hours, using existing plant equipment and procedures, with a best estimate analysis in accordance with the specified IER L1-11-4 assumptions and bases (Reference 8.10).

The strategy in the station procedures includes load shedding to conserve battery life, depressurizing to reduce potential RCS leakage through RCP seals, and removing heat through the steam generators using the ARVs, with the SGs being fed by the turbine driven aux feed pump. Existing analysis, new owner's group analysis, new battery load shedding calculation revisions, and the plant simulator development model were used to make the assessment. An assessment of room environmental conditions and effects on key equipment was also performed.

Also see response to a. above.

i. The plant should have formal engineering calculations for equipment sizing and protection and have approved procedures for connecting the AAC or supplemental power sources to the safety buses.

Response:
The loads required to be fed from the APDGs with their demand are as shown in Table 4. The Table defines total APDG load requirements. The review of the APDG data indicates that the APDG sets are rated to provide more than the required load. The transformer is sized to carry the required loads. The cables from the APDGs to transformer are adequately sized to carry the required loads and the APDG output breaker provides overload protection for these cables. The cables from transformer to 6.9kV bus are also adequately sized and protected. Short circuit protection for equipment and cables is provided by current limiting feature of the APDGs. Formal engineering calculations are not performed for equipment sizing and protection.

j. The EDG or offsite power AOT should be limited to 14 days to perform maintenance activities. This time period is based on industry operating experience; for example, a maximum of 216 hours (13.5 days, consisting of two shifts, each shift working 8 hours) is considered to be sufficient for a major EDG overhaul or offsite power major maintenance. The licensee must provide justification for the duration of the requested AOT (actual hours plus margin based on plant-specific past operating experience).

Response:
Concerning the first scope of work, CPNPP has no plant-specific operating experience (OE) for working on transmission towers. CPNPP has contracted with a transmission construction company to perform the 138kV tower work. The company was founded in 1948 to help build the region's electric power lines. Their crews are among the most experienced in the industry, including many foremen and superintendents who have been with the company for more than 30

years. Additionally, CPNPP's Transmission Operator (TO) subcontracts this company because they are a full-service provider of turn-key transmission structures, lines, and switchyards/substations for new construction, maintenance, storm restoration, and upgrades. The company has many years of OE working in CPNPP's switchyards, including 138kV and 345kV switchyard breakers, air switches, disconnects, and assisted in replacing GSU transformers and has worked for Oncor or CPNPP. As discussed in Section 3.2, Table 1 estimates the first scope of work will take 11.5 days.

Pertaining to the second scope of work, CPNPP has gained valuable OE in the installation of large power transformers with the replacement of four main generator step-up (GSU) transformers. This task involved the coordination of transformer original equipment manufacturer (OEM,) heavy haulers, OEM field service, TO, isophase OEM, site security and site personnel. The GSU replacements occurred in October 2009 and March 2010. Each of the GSU installation milestones (manufacture, shipment, placement and dress out, installed on pad, testing, connection and energization) were completed within or before the defined schedule windows without any major issue. As discussed in Section 3.2, Table 2 estimates the second scope of work will take 52 days.

The OE for the third scope of work is similar to one previously approved by the NRC on October 29, 2010 (ML103190632) that extended, on a one-time basis, the allowable CT of Required Action A.3 for the 345kV inoperable offsite circuit, from 72 hours to 14 days. This change was only applicable to ST XST2 and expired on March 1, 2011 and allowed sufficient time to make final terminations to facilitate connection of either XST2 or the spare ST XST2A to the Class 1E buses. The entire sequence of activities was projected to require approximately 11 days and 13 hours to complete which fit well within the requested 14-day extended CT. The actual CT was 7 days, 21 hours, and 16 minutes. As discussed in Section 3.2, Table 3 estimates the third scope of work will take 12 days.

The main difference between the previous approved license amendment in 2010 and this license amendment request is that there was an installed spare transformer XST2A under the 345kV line that fed XST2 and the 1E buses. Conversely, there is no installed alternate transformer for XST1 thus additional provisions must be made to allow connections and the installation of a new ST. Consequently, this requested amendment will require three primary scopes of work.

Currently, if XST1 requires maintenance that would exceed 72 hours, or if XST1 catastrophically fails, it would take about 18 to 21 days to replace XST1 with the spare startup transformer XST2A. The timing is dependent on the mobilization/availability of heavy haulers, extent of transformer damage, and the availability of needed equipment and personnel to perform the work. Since each ST provides one of the two required offsite AC sources for each CPNPP Unit, an outage of XST1 for greater than the current CT of 72 hours would require that both Units be shutdown to Mode 5 simultaneously.

Once the modification to the plant is complete and XST1 needs maintenance or if XST1 fails, the alternate ST XST1A can be connected to the safety buses to restore the 138kV offsite source within the current TS CT of 72 hours. After maintenance

or repair on XST1 is completed, XST1 may be put back in-service. As a result, XST1A will be a dedicated alternate for XST1 and XST2A will be a dedicated alternate for XST2. Therefore, two one-time 14-day CTs are being requested.

k. An EDG or offsite power AOT license amendment of more than 14 days should not be considered by the staff for review.

Response:
CPNPP is not requesting more than 14-days and is only requesting two, one-time 14-day CTs. Additionally, see response to f. above.

l. The TS must contain Required Actions and Completion Times to verify that the supplemental AC source is available before entering extended AOT.

Response:
This requirement is for a permanent TS change and this amendment request is only applicable to two, one-time, 14-day CTs for XST1.

m. The availability of AAC or supplemental power source shall be checked every 8-12 hours (once per shift).

Response:
During a 14-day CT, the APDG provided for each Unit will be verified available to provide power to equipment for long term cooling once per shift. (See commitments 4441997 and 4457004.)

n. If the AAC or supplemental power source becomes unavailable any time during extended AOT, the Unit shall enter the LCO and start shutting down within 24 hours. This 24-hour period will be allowed only once within any given extended EDG AOT.

Response:
During a 14-day CT, if an APDG becomes unavailable, both Units shall enter Condition C of TS 3.8.1 and start shutting down within 24 hours. (This 24-hour period will only be allowed once within a 14-day CT.) (See commitments 4456419 and 4457005.)

Additionally, the staff expects that the licensee will provide the following Regulatory Commitments:

a) The extended AOT will be used no more than once in a 24-month period (or refueling interval) on a per diesel basis to perform EDG maintenance activities, or any major maintenance on offsite power transformer and bus.

Response:
This requirement is for a permanent TS change for a 14-days; however, this proposed amendment request is not for a permanent TS change, but for two, one-time 14-day CTs. Further, providing the capability for connection of a alternate ST XST1A to the 1E buses within the current TS CT of 72 hours is an improvement in plant design which eliminates the necessity to shutdown both Units if XST1 fails or requires maintenance that goes beyond the current TS CT of

72 hours. This change will improve the long-term reliability of the 138kV offsite circuit by providing connection to the ESF buses through XST1 or the alternate startup transformer. Additionally, performing the work during two, 14-day CTs will provide a safe work environment for personnel safety and will not impact nuclear safety or the health and safety of the public. Therefore, two, one-time 14-day CTs are being requested.

b) The preplanned maintenance will not be scheduled if severe weather conditions are anticipated.

Response:

- Based upon the NOAA weather curves, a time in which severe weather is not expected will be selected for implementation of the XST1 CT. As shown in the weather curves, this time frame is September 1 through March 31. This planned timing will reduce the risk associated with high wind/tornados and weather challenges to the plant during the XST1 CT. (See commitments 4442013 and 4457041.)
- Local weather conditions and forecasts will be monitored by Operations twice per shift to assess potential impacts on plant conditions. (See commitments 4442011 and 4457033.)

c) The system load dispatcher will be contacted once per day to ensure no significant grid perturbations (high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended AOT.

Response:
CPNPP's Operations Department will contact the Transmission Operator (Transmission Grid Controller) once per day during a 14-day Completion Time to ensure no problems exist in the transmission lines feeding CPNPP or their associated switchyards that would cause post trip switchyard voltages to exceed the voltages required by STA-629. (See commitments 4442046 and 4457121.)

d) Component testing or maintenance of safety systems and important non safety equipment in the offsite power systems that can increase the likelihood of a plant transient (Unit trip) or LOOP will be avoided. In addition, no discretionary switchyard maintenance will be performed.

Response:
In response to this requirement, CPNPP makes the following commitments:

- The EDGs, APDGs, TDAFWPs, XST2, CCWPs, and SSWPs will have ALL testing and maintenance activities suspended for the duration of a one-time, 14-day CT for XST1. Additionally, signs will be placed on the doorways to the equipment, or in the case of XST2 around the equipment, noting the restriction of testing and maintenance during this XST1 CT. (See commitments 4442008 and 4457016.)
- Access to both switchyards and relay houses will be controlled and posted, and all maintenance will be suspended for the duration of the CT on XST1. (See commitments 4442028 and 4457119.)

e) TS required systems, subsystems, trains, components, and devices that depend on the remaining power sources will be verified to be operable and positive measures will be provided to preclude subsequent testing or maintenance activities on these systems, subsystems, trains, components, and devices.

Response:
In response to this requirement, CPNPP makes the following commitments:

- Prior to initiation of a one time, 14-day CT extension, PM task for breakers 1EA1-1, 1EA2-1, 2EA1-1 and 2EA2-2 will be verified as current. (See commitments 4442002 and 4457007.)
- Testing of EDGs, APDGs, and TDAFWPs will occur within the two (2) weeks prior to the start of the XST1 CT. (See commitments 4442007 and 4457008.)
- During a 14-day CT, the APDG provided for each Unit will be verified available to provide power to equipment for long term cooling once per shift. (See commitments 4441997 and 4457004.)
- The seismic walkdown will be completed prior to the XST1 CT to identify any issues that could impact the EDGs and TDAFWPs during a seismic event. These impacts include mounting or interactions issues including loose parts and missing hardware. This walkdown is for assurance that these components will meet their seismic design criteria in the event of a seismic incident. (See commitments 4442016 and 4457044.)

f) Steam-driven emergency feed water pump(s) in case of PWR Units, and Reactor Core Isolation Cooling and High Pressure Coolant Injection systems in case of BWR Units, will be controlled as "protected equipment."

Response:
The EDGs, APDGs, TDAFWPs, XST2, CCWPs, and SSWPs will have ALL testing and maintenance activities suspended for the duration of a one-time, 14-day CT for XST1. Additionally, signs will be placed on the doorways to the equipment, or in the case of XST2 around the equipment, noting the restriction of testing and maintenance during this XST1 CT. (See commitments 4442008 and 4457016.)

Compensatory Measures

During the two XST1 extended CTs required to facilitate the modification outage, only one offsite source (XST2) will be available and the current TS would require the shutdown of both Units if XST1 is not restored within 72 hours; therefore, two CTs extension are requested only for the XST1 plant modification. If this requested change is approved, and any other onsite or offsite source or any combination thereof becomes inoperable during the XST1 extended CTs, the current TS CTs would apply and both Units shall shutdown accordingly.

Consistent with other similar NRC approved CT extension requests, Luminant Power provides the following list of compensatory measures in addition to the risk reduction measures discussed in Section 4.2 and commitments associated with the NRC SRP BTP 8-8 to assure safe shutdown and offsite power capability and availability. The summary of regulatory commitments is contained in Attachment 7 to this LAR. The commitments for the first and third scopes of work are the same; however, for commitment tracking and

work control purposes, they have been split into two sets of commitments. The first commitment number(s) is applicable to the 14-day CT for the 138kV tower work and the second commitment number is applicable to the 14-day CT for the 6.9kV work, respectively.

Appropriate just-in-time (JIT) training will be provided to Operations personnel on this TS change as well as the compensatory measures and risk reduction measures to be implemented during these two, one-time, 14-day modification outage. The JIT training will include the loss of the operating ST (XST2) to heighten Operations personnel awareness of challenges to the electrical distribution during the modification outage.

- Just-in-time training for affected work groups will be completed prior to the start of the XST1 outage (Commitments 4442047 and 4457122).

Operations personnel will monitor weather conditions and forecasts and take compensatory measures or risk reduction measures to reduce challenges to plant safety or the electrical distribution system during the modification outage.

- Local weather conditions and forecasts will be monitored by Operations twice per shift to assess potential impacts on plant conditions (Commitments 4442011 and 4457033).

Summary of Deterministic Evaluation

In summary, CPNPP has a robust design with the desired defense-in-depth design features (i.e., the ability to mitigate design basis accidents when a ST is out-of-service). Specifically, offsite and onsite power systems are diverse and redundant and meet regulatory requirements of GDC 17. While XST1 is out-of-service during the plant modification outages, XST2 has the capacity and capability to supply the required safety related loads of both Units.

During the two, one-time, 14-day CTs for XST1, compensatory measures will be in place to assure safe shutdown and offsite power capability and availability. One measure, the APDGs, will provide an alternate power source to one safety related bus in Modes 3, 4, 5, and 6 to maintain the capability for safe shutdown and long term cooling of the Unit. Considering the number of diverse work groups performing work in parallel paths, work groups performing both work scopes, the necessary large lifting equipment and trucks, the limited work space in the area, the safety of the workers, and the health and safety of the public, two, 14-day CTs are being requested. The two, one-time, 14-day CTs will be implemented consistent with station procedures which require consideration of compensatory and risk reduction measures as discussed above and in Sections 4.3 and 4.4, respectively, below to mitigate the consequences of an accident occurring while XST1 is inoperable.

Further, providing the capability for connection of a alternate ST XST1A to the 1E buses within the current TS CT of 72 hours is an improvement in plant design which eliminates the necessity to shutdown both Units if XST1 fails or requires maintenance that goes beyond the current TS CT of 72 hours. This change will improve the long-term reliability of the 138kV offsite circuit by providing connection to the ESF buses through XST1 or the alternate ST. Additionally, performing the work during two, 14-day CTs will provide a safe work environment for personnel safety and will not impact nuclear safety or the health and safety of the public.

4.2 Probabilistic Evaluation

Tier 1 of the three-tiered approach described in RG 1.177 (Reference 8.2) for evaluating the risk associated with a proposed TS allowed outage time (AOT or Completion Time (CT) as used in the Improved Standard Technical Specifications) requires an evaluation of the effect on plant risk of the proposed change. The Tier 1 portion of the proposed change discusses the adequacy of the CPNPP Probabilistic Risk Assessment (PRA), the quality and conformity of the PRA model with RG 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," (Reference 8.12) and provides the detailed description of the risk assessment and affect of the proposed change on CDF, LERF, incremental conditional core damage probability (ICCDP), and incremental conditional large early release probability (ICLERP).

4.2.1 PRA Quality Requirements

The scope and quality requirements and the related documentation required for this submittal are provided in Appendix A of this Attachment. First, the documentation required by Section 4.2 of RG 1.200 "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" (Reference 8.12) to demonstrate the technical adequacy of the CPNPP PRA is discussed and provided as appropriate. Second, the details of the findings and observations (F&Os) from the peer review are documented and addressed. Together these demonstrate the technical adequacy of the CPNPP PRA model to address the risk impact of the proposed license amendment.

4.2.2 Risk Assessment

The details of the risk assessment are presented in this Section. The risk assessment is broad and includes all hazard groups and plant operational states applicable to the two, one-time 14-day CT extensions.

Using the governing guidance documents RG 1.174 (Reference 8.1] and RG 1.177 (Reference 8.2), the following risk importance measures are identified to be evaluated based on the proposed two, one-time 14-day CTs to Technical Specifications (TS):

- Changes in Core Damage Frequency (ΔCDF)
- Changes in Large Early Release Frequency (ΔLERF)
- Incremental Conditional Core Damage Probability (ICCDP)
- Incremental Conditional Large Early Release Probability (ICLERP)

The guidelines for the ICCDP and ICLERP that can be considered in this evaluation for the determination of acceptability for the proposed two, one-time 14-day CTs to TS are an ICCDP < 1E-05 and ICLERP < 1E-06 as stipulated in RG 1.177 (Reference 8.2). This threshold is appropriate given that effective compensatory measures are in place to reduce the overall risk increases.

However, for the purposes of this PRA evaluation the stricter criteria for permanent changes from RG 1.177 (Reference 8.2) and RG 1.174 (Reference 8.1) were applied (ΔCDF and ICCDP < 1.0E-06 and ΔLERF and ICLERP < 1.0E-07), beyond those set forth for this proposed two, one-time 14-day CTs to TS.

Description of Risk Assessment

For this license amendment request (LAR), the scope of the risk assessment will include all hazard groups and plant operational states applicable to the TS change. Specifically, this analysis will quantitatively address CDF and LERF for internal events, including internal flood, for at-power operation. Qualitative assessments will be performed for fire events, seismic events, tornado events, and other external events; for some of these qualitative assessments limited risk insights from the CPNPP Individual Plant Examination of External Events (IPEEE) will be used. The following lists common model attributes used in this analysis:

- All STs are located inside of the protected area and not in the switchyard.
- Each of the transformers (XST1, XST2, and XST2A) are different in design/manufacture and therefore they are not impacted by common cause failures.
- The base model is the Revision 4A at-power test and maintenance model for internal events, including internal flooding.
- The CPNPP PRA model does not allow recovery of faulted or out-of-service equipment.
- Failure modes and rates for important components are shown below (note that the fail to run/operate frequencies are all based on the CPNPP PRA mission time, 24 hours):

  - Emergency Diesel Generator Fail to Start 3.80E-03
  - Emergency Diesel Generator Fails to Run 1.24E-02
  - Turbine Driven Aux Feedwater Pump Fail to Start 2.49E-03
  - Turbine Driven Aux Feedwater Pump Fail to Run 1.66E-03
  - Transformer Fail to Operate 2.16E-05

Assessment of Internal Events

As previously stated, the proposed TS change involves a one-time extension to the CT for the XST1 transformer from 3 to 28 days (in two 14-day CT periods). To facilitate this analysis, the base PRA model was re-quantified with the XST1 transformer out-of-service (OOS) (basic events set to "True") and then compared to the base-case frequencies. This condition is reflected in the base PRA model. The yearly frequencies for the base and XST1 OOS cases ("x") for CDF and LERF are shown in Table 6 below. These yearly frequencies are based on remaining in the plant configuration for an entire reactor year.

Table 6: Risk Assessment Input Values

Unit	Input Parameters	Frequency (Per Year)
Unit 1	CDF(base)	3.01E-06
	CDF(x)	3.15E-06
	LERF(base)	2.14E-07
	LERF(x)	2.21E-07
Unit 2	CDF(base)	3.00E-06
	CDF(x)	3.15E-06
	LERF(base)	2.14E-07
	LERF(x)	2.21E-07

NOTE: The numbers presented in the tables have been rounded from the actual values.

The calculation methods for CDF_{New}, ΔCDF, ICCDP, are shown below in the following equations.

$$CDF_{NEW} = \left(\frac{T_{CT}}{T_{Year}}\right) * CDF_X + \left(1 - \left(\frac{T_{CT}}{T_{Year}}\right)\right) * CDF_{Base} \qquad \text{[Eq. 1]}$$

$$\Delta CDF = CDF_{New} - CDF_{Base} \qquad \text{[Eq. 2]}$$

$$ICCDP = (CDF_X - CDF_{Base}) * CT_{New} \qquad \text{[Eq. 3]}$$

Where:

CDF values are represented for a 365-day period (annual)

CDF_{Base} = baseline CDF for the at power (Mode 1) internal events

CDF_X = CDF for the specific CT case
T_{CT} = total days the XST1 transformer is to be out-of-service for this CT extension LAR, 28 days (in two 14-day CT periods)
T_{Year} = time equivalent to one reactor year or 365 days of full power operation

CT_{New} = time in years the XST1 transformer is to be out-of-service for this LAR, 7.67E-02 years, (28 days (in two 14-day CT periods))

Note: Each of the equations seen above is also used to calculate the new LERF, ΔLERF, and ICLERP by replacing the CDF values with the corresponding LERF values.

Eq. 1 is used to create a weighted CDF for the baseline and XST1 OOS conditions, with the weight being the fraction of time each condition is to exist. The resulting CDF_{New} from Eq. 1 is then compared to the baseline CDF to calculate the change in CDF (ΔCDF) in Eq. 2, in accordance with RG 1.174 (Reference 8.1). The ICCDP in Eq. 3 is calculated in accordance with RG 1.177 (Reference 8.2). It should be

noted that the base and specific configurations for the plant, while in the extended CT, are the same in both Eqs. 1 and 3, and thus the ΔCDF is equal to the ICCDP. The results of these calculations are in Table 7 below.

Table 7: Risk Assessment Output Values

Unit	Output Parameters (XST1 OOS)	Value	Frequency
Unit 1	CDF_New	3.02E-06	Per Year
	Delta CDF	1.14E-08	Per Year
	ICCDP	1.14E-08	Dimensionless
	LERF_New	2.15E-07	Per Year
	Delta LERF	5.35E-10	Per Year
	ICLERP	5.35E-10	Dimensionless
Unit 2	CDF_New	3.01E-06	Per Year
	Delta CDF	1.14E-08	Per Year
	ICCDP	1.14E-08	Dimensionless
	LERF_New	2.15E-07	Per Year
	Delta LERF	5.42E-10	Per Year
	ICLERP	5.42E-10	Dimensionless

***Baseline values used for these calculations are located in Table 6**

NOTE: The numbers presented in the tables have been rounded from the actual values.

The values shown in Table 7 were calculated without crediting any risk reduction measures. During normal plant operations, there are certain work activity restrictions; the most important of these are: no work on the Emergency Diesel Generators (EDGs), no work on Alternate Power Diesel Generators (APDGs), no work in the 138kV/345kV switchyards, no work on the in-service ST, and no work on the TDAFWPs scheduled simultaneously. These maintenance restrictions are procedurally driven but no credit was taken for them in the quantifications for XST1 out-of-service.

Together with normal procedural restrictions on test and maintenance, additional risk reduction measures are planned to be in place and are listed below. These risk reduction measures are specific to internal events; further risk reduction measures are considered for the full risk analysis. The complete list of risk reduction measures can be found in Section 4.3.

1. All four EDGs, both APDGs, and both TDAFWPs will be tested in the two weeks preceding the start of the XST1 CT periods. This is to assure the reliability of these components which are important to the mitigation of the loss of offsite power (LOOP) and station blackout (SBO) scenarios. This action provides a potential increase in reliability for these components.
2. The time of year when weather conditions are more favorable will be selected. This action diminishes the potential for an occurrence of a LOOP due to weather.
3. Maintenance and testing on the 345kV and 138kV switchyards will not be allowed. This action is planned to improve availability of offsite power.

4. Maintenance and testing on in-service ST XST2, all four EDGs, both APDGs, both TDAFWPs, Component Cooling Water Pumps (CCWPs) and Station Service Water Pumps (SSWPs) will be suspended for the duration of the XST1 extended CT. As part of normal plant operations, work on the TDAFWPs, EDGs, APDGs, and XST2 is procedurally restricted at any time maintenance is occurring on the XST1 ST. It is included as part of the stated risk reduction measures to show a firm commitment to plant practices.

For the quantitative risk analysis, none of these risk reduction measures are credited. The results from the quantitative evaluation demonstrated a non-risk significant increase to the plant with a ST out-of-service. The increase in risk was found to be associated with the failure of the remaining in-service ST, XST2, and its supports followed by the failure of the EDGs. This minimal increase in risk was determined to be appropriate based on the reliability of STs/supports and their associated failure rates. Further discussion and examination of the results of the internal events analysis is provided in Section 4.3.

A recent modification to CPNPP (included in the CPNPP PRA model of record (MOR) - Revision 4A) is the installed APDGs as an additional onsite power source, one set of APDGs for each Unit. The APDGs can power either Train A or B, 6.9kV 1E buses. The APDGs are relied upon when there is a LOOP and the EDGs fail to provide power. Equipment powered by the APDGs per SOP-614A/B (Reference 8.8) essential to provide long term cooling in the PRA model is SSW, CCW, safety chillers, battery chargers, instrument air, and a CCP or a RHR pump. In conjunction with the TDAFWP, the loading allowed for by the APDG is sufficient to bring a Unit to a safe stable condition.

Assessment of Fire Events

Introduction

This portion of the LAR analysis focused on the fire risks during the extended CT for the XST1 ST. During the extended CT both Unit 1 and Unit 2 6.9kV safeguards buses are to be powered by the in-service ST XST2. The fire analysis for this LAR was performed using a blended qualitative and quantitative approach based on the methodology employed by the "Individual Plant Examination of External Events: Fire Evaluation, Comanche Peak Steam Electric Station" (Reference 8.13). A brief description of the IPEEE Fire Analysis was excerpted from the IPEEE document ER-EA-005 executive summary shown below:

> A Level-I Probabilistic Risk Assessment (PRA) method was used to evaluate the fire risk for CPSES Units 1 and 2. The steps and general guidelines described in NUREG-1407 and NUREG/CR-2300 were followed. The EPRI fire events database was used for the quantification of core damage frequency due to fire. In addition, the fire propagation and damage assessment models developed in the fire induced vulnerability evaluation (FIVE) methodology were used for the purpose of screening.

In addition to the information contained in the summary above, the IPEEE followed methodology contained within the Electric Power Research Institute (EPRI) Fire Risk Application Guide (Reference 8.14) for the detailed fire analysis, non-screened scenarios and zones. The CPNPP IPEEE Fire Evaluation does not meet the standards defined in RG 1.200 Revision 2 (Reference 8.12) Section 1.2.4 for acceptability. A review of the IPEEE was performed and documented in Appendix B. Differences noted between the RG 1.200 requirements and the IPEEE model that were determined to potentially impact the results of this analysis were addressed specifically. Details regarding how the differences were addressed are documented in this evaluation.

Preliminary Analysis

The discussion for this extended CT focused on fire scenarios that affect the offsite power feeds, cabling and supports, from the STs to the 6.9kV buses. A fire that affects the offsite power sources during the time when the XST1 ST is out-of-service could result in a direct loss of offsite power if the fire impacts the in-service ST cabling or supports. An individual fire scenario that affects a ST's cabling would result in the ST disconnecting from all its associated loads. For fire scenarios that do not affect the offsite power sources, the characteristics and magnitude of a change to a fire scenario in the plant as a result of the XST1 ST being out-of-service would be similar to the internal events analysis that was previously discussed. These fire scenarios were similar to resulting changes (deltas) from the internal events analysis. The changes would be associated with the failure of a single in-service ST and no new failure modes would be introduced as a result of the XST1 ST being out-of-service, beyond those already included in the internal events model. The results of the internal events analysis for this configuration demonstrated that the increase in risk for a single ST in-service, vice two, was not risk significant. This non-significant increase in risk was associated with the low failure rates for the in-service ST and its supporting equipment, further supported by the discussion of the ST reliability in the deterministic Section of this proposed amendment.

Fire scenarios that affect offsite power feeds are more likely to impact plant risk beyond what was seen in the internal events analysis with a ST being out-of-service. In particular fire scenarios that directly impact the offsite power feed from the in-service ST XST2 would result in a loss of offsite power to the 6.9kV buses while XST1 is out-of-service.

To perform this focused analysis, walkdowns of the power and control cabling from each of the STs (XST1 and XST2) to the safety related 6.9kV buses (1EA1/1EA2/2EA1/2EA2) were performed to confirm and verify their routing. During the walkdown the transformer cabling was examined for potential fire sources (scenarios) that would result in the loss of power from the in-service ST (XST2). Additionally, fire in the in-service plant ST (XST2) was also re-examined.

Walkdown Analysis

The walkdowns were performed to verify both of the ST's cable routings through the fire zones (rooms) where the cabling exists and further identify the fire sources (scenarios) in each of the zones that could impact the offsite power feeds. The walkdown revealed multiple fire zones of interest for potential re-

examination. Upon confirming the fire zones the IPEEE analysis was consulted. Based on information contained in the IPEEE in conjunction with the walkdowns, some fire zones were determined to not require further examination and thus could be screened from this risk assessment. It was also noted that the walkdown did not identify any new fire scenarios that were not previously included the IPEEE fire analysis.

The fire zones that were not required to be further examined are broken down into three categories: (1) the cables for XST1 and XST2 are in close proximity to each other and are both damaged by the fire scenarios in the zone, (2) the IPEEE analysis used a hot gas layer screening assessment for the fire zone, or (3) there were no fire sources (scenarios) identified that could impact the cabling.

For category (1) the impact of having the ST XST1 in an extended CT would not result in a risk increase. In this case the fire would burn through and damage both STs' (XST1 and XST2) cables thus rendering both offsite power supplies to the 6.9kV safeguards buses unavailable. Therefore having 1 or 2 STs available during a fire for this scenario would not influence the risk results.

Similarly the impact for category (2), the hot gas layer screening in the associated fire zones, extending the CT for XST1 would not increase the risk. The hot gas layer screening scenarios assume that everything in the room is destroyed by the fire, including the ST cabling. The previous risk results for these zones were very low such that a further analysis was not required. It should also be noted that any room that was screened using this method contained the cabling from both STs and consequently result in no change in risk for a single ST out-of-service.

For category (3) the fire zones did not require analysis as there were no fire sources identified that could impact the ST cables. The lack of fire sources was confirmed using the IPEEE analysis and the associated walkdown.

After reviewing all of the fire zones a total of four fire scenarios were identified, three of the identified scenarios were in Unit 1 and one scenario was identified in Unit 2. Further discussion of the re-analysis on these scenarios is in the Detailed Analysis Section of this document. It should be noted that the one scenario identified in Unit 2 is the same scenario as one of the three identified in Unit 1 and is related to a transient fire scenario. The remaining two scenarios identified in Unit 1 are not found in Unit 2 due to dissimilarity in the routing of the ST power cables and associated with fixed source scenarios.

Detailed Analysis

This portion of the fire analysis was performed using the insights gained from the plant walkdowns in conjunction with the IPEEE fire analysis. It is recognized that the CPNPP IPEEE fire analysis does not meet the current RG 1.200 Revision 2 standards in Section 1.2.4, and therefore quantitative analyses performed using the IPEEE information cannot be directly applied to the limits defined in RG 1.177 Revision 1 (Reference 8.2). However, based upon the significant margins noted in the internals model (including internal flooding) CPNPP believes it is acceptable to use the results of an analysis based upon IPEEE fire results for risk insights. Therefore, the information from the IPEEE will be reviewed and re-quantified to determine the potential risk significance of this extended CT of fire with respect to risk significant equipment and plant configurations that may be identified.

In an effort to improve the quality of the insights that will be gained from the IPEEE model a review of Section 1.2.4 of RG 1.200 was performed, see Appendix B, and the differences determined to potentially impact the risk results are addressed in this Section. While in general the IPEEE fire analysis contained much of the information required in Table 5 of RG 1.200 Section 1.2.4 the model was developed using industry standards that have been superseded. The fire frequencies and fire suppression system unavailability values are based on the industry guidance developed by the EPRI Fire Risk Implementation Guide (Reference 8.14). The IPEEE does contain information relating to plant boundary definitions, equipment/cable selection, fire scenario selection, scenario analysis, quantitative screening, quantification, etc. However since the IPEEE analysis was developed, the industry has become more aware of additional fire risks that were not previously assessed. Aside from newer industry guidance on portions of the IPEEE analysis notable differences were found to be fire induced spurious actions (otherwise known as "hot shorts") and circuit analysis. To address the potential impact of fire induced spurious operations this re-analysis will be performed by reviewing the equipment cables identified in the IPEEE for the identified fire scenarios of importance, determining the impact of a spurious operation on each component affected by the fire scenario, and incorporating the impact into the PRA model for quantification as appropriate.

The IPEEE fire analysis for damage caused by a fire source was performed using the "Fire Risk Analysis Implementation Guide" (Reference 8.14). The results of the damage analysis were documented in the associated IPEEE documents and included the targets (cable raceways and conduits) that were damaged by each of the fire scenarios. The resulting damage from each fire scenario was then incorporated into the IPEEE fire database. This database was used to determine the Individual Plant Examination (IPE) equipment that was failed as a result of each fire scenario. While the database was explicit on equipment that was contained in the IPE, it did not include equipment that was not part of the IPE model. However the database did retain the affected raceways and conduits for components that were not modeled in the IPE. For this analysis it was important to determine which fire scenarios contained equipment not in the IPE model. The impact of fire induced spurious operations on non-IPE components may result in consequences not revealed in the IPEEE analysis. Based on the fire scenarios identified for this LAR only one scenario resulted in damage to cable conduits and raceways containing non-IPE components. This scenario is discussed further for the potential impacts of non-IPE components on the fire risk insights later in this Section. It should be noted that cable raceway and conduit layouts have changed minimally in the plant since the creation of the IPEEE evaluation, and thus the information contained within the fire database was determined to remain valid.

The identified fire scenarios of interest were reviewed in the IPEEE fire documentation and databases to determine what components were impacted by each fire scenario. In the original analysis the fire impacts were only performed assuming that the component affected by the fire was damaged and thus unavailable to perform its mitigating function. However based on the current state of knowledge regarding fire induced spurious operations, the simple failure of a component may or may not be the worst case impact for the affected function. A line by line review approach was taken in analyzing each component

affected by the fire. This approach was done to determine the worst case position for failure of each component. For valves, failure in the open, closed, or as-is positions were considered. For pumps and other components, spurious starting or stopping was considered. No attempt was made to identify whether the cabling affected by the fire scenario was for power or control. It was assumed that if the worst case for each component was a change of state/position then the cable in the tray was capable of causing the spurious action. For the majority of the components affected it was determined that failure of the mitigating function was the worst case, but for a few sets of valves and components transferring state/position would result in the more undesirable configuration.

The few components that were determined to result in undesired impacts from spurious operation were broken down into two categories. One of these categories was assumed to have the spurious operation occur as a direct result of the fire and the other category assigned a probability of spurious operation. The first group of components consisted mostly of valves that, if spuriously operated, could isolate a flow path from either an emergency core cooling system (ECCS) pump or an auxiliary feed water pump. The second group of components was found to potentially result in an interfacing systems loss of coolant accident (ISLOCA), a reactor coolant pump (RCP) seal loss of coolant accident (LOCA), or a spurious safety injection. The first group of components had varying impacts to all four of the fire scenarios while the second group did not affect all of these fire scenarios. For the second group of components the three fire scenarios they could impact were all affected by the three spurious actions identified. This is because the cable trays associated with the second group of components were found to run over each of the three sources.

An in depth review of the fire induced spurious operations that potentially result in an ISLOCA, RCP seal LOCA, or a spurious safety injection was then conducted. For the RCP seal LOCA there were two valves identified that would have to spuriously operate for this result in an event to occur. One of these valves was in the flow path of the thermal barrier cooling to the RCPs and its closure would result in a loss of thermal barrier cooling. The other valve that was identified was in the flow path of the RCP seal injection and its closure would result in a loss of seal injection. Therefore in order for the RCP seal LOCA to occur, both of these valves would have to spuriously operate during a fire. As for the potential fire induced safety injection, these cables were associated with the sequencer.

Lastly the components associated with the potential ISLOCA were reviewed. The components identified for the potential ISLOCA were associated with the Train A residual heat removal (RHR) shutdown cooling suction line from reactor coolant system (RCS) hot leg 1 (1-8701A and 1-8702A). Spurious actuation of both of these valves could result in an ISLOCA; however, per the CPNPP Fire Protection Report (Reference 8.15) Section 4.3.2.3.1, spurious actuations are precluded for these valves as "One of two series boundary isolation valves (e.g., the Reactor Coolant System/Residual Heat Removal System Valves) can be locked in its safe (closed) position; that is, with its respective power supply breaker open and in the off position." Additionally, the design basis document DBD-ME-260 (Reference 8.16) was consulted and confirmed by plant procedure SOP-102 (Reference 8.17) to verify that both of these valves are closed with power

locked out when a steam bubble is in the pressurizer until the reactor is cooled down to Mode 4 and RHR system is initiated. Therefore, these valves are prevented from inadvertent opening at-power (Mode 1) and would not result in an ISLOCA for these fire scenarios.

Subsequent to the fire induced spurious operations being identified, a combined list of the components for each of the fire scenarios was created to include those that were not determined to have additional adverse affects from fire induced spurious operations. The list of component impacts for each of the scenarios was then reviewed and the PRA model was modified to incorporate the fire induced spurious operations. The model modifications were necessary to incorporate the fire induced spurious operations for an RCP seal LOCA and an inadvertent safety injection (SI). The modifications were completed such that the fire could occur with no induced spurious operations or the fire would occur with one of the two induced spurious operations. Combining of the two fire induced spurious operations was not allowed as a spurious SI signal in conjunction with an RCP seal LOCA would be a beneficial failure. If the two fire induced spurious actions were combined, ECCS equipment would receive the signals to start and realign to mitigate the RCP seal LOCA without requiring signal actuation equipment to respond. These fire induced spurious operation events (RCP seal LOCA and spurious SI) were given a probability of 5E-01. This value was selected as CPNPP has not completed detailed circuit and cable analyses; a high probability was chosen such that risk insights from these events would be apparent in the quantitative cutset results.

With the addition of the fire induced spurious operations, the impacts (including the spurious actions assumed with the fire scenarios) were reviewed and the appropriate basic events in the model were identified. For Unit 1 there were three fire scenarios identified that involve two fixed source fires associated with components in the Train A 6.9kV switchgear room and one transient fire scenario that occurs in the hallway outside of the switchgear room. This same transient fire scenario was also identified as a Unit 2 scenario based on mirror image physical spatial characteristics; however, the fixed scenarios do not appear in Unit 2 due to differences in cable routing.

For the Unit 1 and Unit 2 transient scenarios (TSN4-082, transient combustibles storage area), it was noted that the baseline fire would result in significant damage to Train A equipment in addition to the loss of the ST XST2. The results for the two Unit 1 fixed source scenarios FSN4-083 and FSN7-083 [6.9kV to 480v transformer (CP1-EPTRET-03) and MCC1EB1-1 (CP1-EPMCEB-01), respectively] were similar due to the significant damage to Train A equipment and the loss of XST2. Given the location of these fire scenarios (in or near the Train A switchgear room), the damage from these fires is not unexpected as all power to Train A components is directed through these areas. Therefore, based on the expected damage from each of these scenarios, the Train B equipment and supports were found to have significant importance to mitigate the evaluated fire events.

Fire scenario FSN7-083 is a 480V motor control center (MCC) that was determined to be potentially susceptible to high energy arching faults (HEAF). The IPEEE analysis did not consider HEAFs as a fire initiating event and must therefore be considered in this analysis. The methodology applied in the IPEEE

analysis assumed a fire plume that damaged all of the targets above the MCC. The HEAF zone of influence (ZOI), as described in Appendix M of NUREG/CR-6850 (Reference 8.18) is broken into two zones, one above the top of the cabinet and one horizontally from the front/rear panels. The ZOI above the cabinet extends 5 feet vertically from the top of the cabinet and 1 foot horizontal from the front and rear panel. The horizontal ZOI extends 3 feet from either the front or rear panels/doors. Targets located within those zones will suffer physical damage and functional failure at the time of the HEAF. Based on a visual walkdown it was determined that there were no components within a 3 foot horizontal distance that could be impacted by a high energy explosion and the targets within the vertical HEAF ZOI are included in the IPEEE MCC fire scenario. Therefore the IPEEE fire analysis methodology incorporated the potential damaging effects resulting from a HEAF and there are no additional risk insights for this extended CT. The other fixed scenario (FSN4-083) and the transient fires (TSN4-082) were determined to not be impacted by HEAFs.

For fire scenario FSN4-083 it was identified that there are cable conduits and raceways affected which did not have their components mapped in the IPEEE database analysis. As the equipment in these raceways and conduits were unknown it represented a potential for missed insights in this overall analysis. However given the severity of the damaged caused by this fire, complete loss of Train A mitigation equipment and the fire-induced spurious actuation that would cause an RCP seal LOCA, it is not likely that the unknown non-IPE equipment would further influence the risk insights from this risk assessment. This was further supported by a review of the primary impacts of fire induced spurious operations that were not included in the fire analysis. The potential for fire induced spurious draining of large tanks key to mitigation was assessed by reviewing the tanks contained in the PRA model (condensate storage tank (CST), refueling water storage tank (RWST), diesel fuel oil storage, surge tanks, etc.) and verifying them to have manual drain valves. Therefore fire induced spurious draining of these tanks is not probable. In addition to spurious draining of tanks, plant systems typically have drain valves that are only opened via manual operation and therefore they are considered to not be affected by fire induced spurious draining. Spurious operation of equipment affecting both trains of equipment was also considered, but based upon the plant design this was determined to be unlikely as train separation in both Units exists and is maintained per 10CFR50 Appendix R fire requirements. These observations further confirmed that it is unlikely that unknown fire induced spurious operations would result in changes to the risk insight for this fire scenario.

With the model modifications completed and the associated fire damage impacts mapped, the PRA model was quantified for each of the fire scenarios. The quantification was performed using the baseline fire where the XST1 ST remained in-service and the XST1 out-of-service configurations. The quantifications were performed using a probability of 1 for each of the fire scenarios initially and the resulting conditional core damage probabilities (CCDPs) were multiplied by the individual fire ignition frequencies. No credit was taken for fire suppression for any of the fire scenarios contained in this analysis. All equipment that is determined to be damaged in each of the fire scenarios is therefore considered failed or, if applicable, impacted by a hot short. Quantification using this method was performed at a truncation limit of 1E-14 (the same used in the internal events model) to ensure that a significant amount of cutsets were included in the results evaluation.

The quantification was also performed for a fire in the XST2 ST. For the baseline scenario, the XST1 ST was in-service. In the XST1 extended CT scenario, neither ST would be available resulting in a LOOP. The quantifications did not take credit for any compensatory actions. The results of the quantifications are shown below in Table 8 for Core Damage results and Table 9 for Large Early Release results.

A sensitivity analysis was performed for spurious operations involving postulated fire scenarios that did not impact the cabling from the STs. These sensitivities were performed for spurious power operated relief valve (PORV) LOCA and ISLOCA. The change in the results of these sensitivities for the XST1 out-of-service were similar to those found in the internal events analysis, i.e. the change in the cutsets were related to the failure of the in-service ST (XST2) or its supports combined with the failure of the EDGs. Therefore the risk insights and risk reduction measures from the internal events analysis are applicable to these scenarios.

Table 8: Fire Analysis Quantitative Core Damage Results

Unit	Fire Scenario	CDFBaseline (Per RX Year)	CDFNew (Per RX Year)	Delta CDF	ICCDP
1	FSN4-083	7.10E-08	1.52E-07	8.15E-08	8.15E-08
	FSN7-083	8.85E-09	2.80E-07	2.71E-07	2.71E-07
	TSN4-082	8.82E-08	1.89E-07	1.01E-07	1.01E-07
	XST2 Fire	1.47E-09	6.14E-08	6.00E-08	6.00E-08
	Total =			5.13E-07	5.13E-07
2	TSN4-082	7.39E-08	1.77E-07	1.03E-07	1.03E-07
	XST2 Fire	6.09E-10	6.06E-08	6.00E-08	6.00E-08
	Total =			1.63E-07	1.63E-07

NOTE: The numbers presented in the tables have been rounded from the actual values.

Table 9: Fire Analysis Quantitative Large Early Release Results

Unit	Fire Scenario	$LERF_{Baseline}$ (Per RX Year)	$LERF_{New}$ (Per RX Year)	Delta LERF	ICLERP
1	FSN4-083	2.95E-09	6.44E-09	3.49E-09	3.49E-09
	FSN7-083	2.91E-10	1.19E-08	1.16E-08	1.16E-08
	TSN4-082	3.67E-09	8.00E-09	4.34E-09	4.34E-09
	XST2 Fire	6.03E-11	2.61E-09	2.55E-09	2.55E-09
	Total =			2.20E-08	2.20E-08
2	TSN4-082	3.07E-09	7.45E-09	4.38E-09	4.38E-09
	XST2 Fire	2.39E-11	2.57E-09	2.55E-09	2.55E-09
	Total =			6.93E-09	6.93E-09

NOTE: The numbers presented in the tables have been rounded from the actual values.

Fire Analysis Conclusions

The numerical results shown in the Tables 8 and 9 above do meet the criteria set forth in RG 1.177 for acceptability (ΔCDF and ICCDP < 1.0E-06 and ΔLERF and ICLERP < 1.0E-07). However, because the CPNPP IPEEE model does not meet the current standards and thus these values cannot be directly applied. Instead, a detailed review of the cutset results was performed that focused on the overall fire insights for the change in risk given the XST1 ST out-of-service for the extended CT.

Similar to the baseline results, each of the fire scenarios showed significant impacts to Train A components and the loss of offsite power from the fire induced failure of XST2. The resulting changes to each of the fire scenarios' cutset results with the XST1 ST out-of-service were dominated by RCP seal LOCAs that were a result of the direct loss of offsite power in conjunction with failure or test and maintenance (T&M) events associated with the Train B EDG and its supporting equipment (ventilation fans, diesel fuel oil pumps, etc.). It should also be noted that the APDGs were not credited for this analysis. Depending on plant conditions as a result of the fire, the APDGs could be connected (procedurally supported) to the unaffected B Train electrical bus in the event of an EDG failure to help mitigate the RCP seal LOCA.

Review of the quantitative results noted that the impact of the fire induced spurious operations with the XST1 out-of-service was small. In the XST1 out-of-service quantifications, the failure of the EDG or its supports represents a single event that results in both the RCP seal LOCA initiator and failure to mitigate the event thus leading to core damage. In the baseline result the fire induced spurious operations appear but they require additional equipment failures, in XST1 or its supporting equipment, to prevent mitigation of the event and lead to core damage.

Based on the results of having the XST1 in an extended CT, the risk reduction measures identified by the internal events analysis and documented in Section 4.3 are also applicable for this fire analysis. Specifically the risk reduction measures for testing of the EDGs prior to CT entry and restricting of maintenance/testing activities on the EDGs throughout the duration of the extended CTs provide further risk reduction for these fires. The following additional risk reduction measures were developed to address the fire risk insights not covered by the risk reduction measures developed from the internal events analysis:

- Additional restrictions will be in place during the extended CTs regarding the storage of transient combustibles in the two combustible storage areas discussed in this fire analysis (Unit 1 and Unit 2, TSN4-082) and along the path of the XST2 cabling.
- Perform thermography on the two fixed sources identified in Unit 1 (FSN4-083 CP1-EPMCEB-01 and FSN7-083 CP1-EPTRET-03) to ensure no abnormalities exist that could lead to a fire in these two components prior to entry into the extended CTs.
- Roving hourly fire watches of the XST2 cabling routes for additional fire detection throughout the duration of the extended CTs.
- Ensure availability of the APDGs as an additional power supply (testing APDGs prior to CT entry and no test or maintenance activities during the extended CT).
- All hot work activities along the routing associated with power and control cabling for XST2, the in-service ST, will be suspended during the XST1 CT. This is to reduce the risks associated with fires that could damage and thus disable the XST2 transformer cabling.

The risk insights of the fire analysis for this proposed LAR have provided assurance that the impact of having one ST (XST1) out-of-service for the 28 day CT (two, 14-day CT windows) is of low risk significance. This was concluded based on review of the overall fire impacts, both qualitative and quantitative. The low likelihood of the in-service ST randomly failing or a fire affecting the XST2 cabling provides additional assurance that the risk impacts due to fire remain small. Additionally, various risk reduction measures are being put into place to prevent or reduce the likelihood of the fire scenarios that potentially impact XST2 during the two, one-time, 14-day CTs for XST1. Therefore based upon this analysis and the risk reduction measures, the fire risk impact of the ST CTs for XST1 being extended from 3 to 28 days (two 14 day CT windows) is considered to be of low risk significance.

<u>High Wind/Tornado</u>

The impact of high wind/tornado events on the ST XST1 CT extensions will be discussed with reference to two representative scenarios: 1) the high wind/tornado event occurs on the plant site (protected area/switchyard) and 2) the high wind/tornado event takes place offsite and affects offsite power lines. For both of these scenarios there is damage assumed due to direct wind effects on systems, structures and components (SSCs) and damage due to induced missiles. CPNPP's design basis, from the CPNPP FSAR (Reference 8.3), for high wind/tornado events is the following:

- Seismic Category I structures are designed for 300 mph wind (Fujita scale 5 (F5)).
- The Turbine Building is designed for industrial standards of 150 mph winds (F3).
- The switchyard is designed for 80 MPH winds (F1).
- Winds below 80 MPH (F0) are within the design basis of plant equipment.

In scenario (1) a high wind/tornado event is assumed to occur on the plant site (protected area/ switchyard) and is highly unpredictable, erratic, and destructive. Per the CPNPP IPEEE Tornado Risk Assessment (Reference 8.19), all tornado strikes/high wind events with wind speeds in excess of 80 mph (F1 and higher) can be assumed to result in a loss of offsite power (LOOP). This assumption is based on the design for the switchyard, as stated above, that an F1 tornado will result in damage significant enough to render it inoperable.

The physical layout of CPNPP has the protected area in close proximity to the switchyard. Given that both of the STs are located in the protected area on the west/south side, close to the switchyard, and the unpredictability of a high wind/tornado event, damage incurred by the event will render the switchyard and both STs inoperable. Therefore, XST1 being out-of-service for maintenance would not directly affect the outcome of the high wind/tornado event.

Additionally, for tornados F3 and greater the Turbine Building would be assumed to be lost along with the capability to recover offsite power. This is due to the cable trays for XST1 and XST2 both being routed through the turbine building. Thus, the impact of these CT extensions on scenario (1) results in an equivalent risk result to the CPNPP IPEEE Tornado Risk Assessment (Reference 8.19) whether both STs, XST1 and XST2, were in-service or one ST is OOS at the time of the high wind/tornado event.

Scenario (2) involves a high wind/tornado event occurring outside of the protected area/switchyard and affecting offsite power lines. For this scenario the offsite power lines are assumed to be of the same robustness as the switchyard and therefore would also be rendered inoperable in any high wind/tornado condition greater than or equal to an F1. As this scenario occurs offsite, it does not directly affect either of the STs or the CPNPP switchyard through wind effects or generated missile damage. However, the event will cause a LOOP due to the unavailability of the incoming (offsite) power feeds. Therefore, regardless of whether or not the STs are in-service, a similar situation would exist where offsite power has been lost through damaged power lines, i.e. the recovery of offsite power would depend on the ability to repair power lines and not plant equipment (including the STs). However, with the XST1 OOS, there is only one recovery path and the recovery of offsite power is limited to the 345kV switchyard. To address this configuration, as it also affects the at power internal events model while in a single ST outage, a sensitivity study was performed using the base PRA model. The results of this sensitivity study (detailed in Section 4.3) showed the impact to offsite power recovery from XST1 being out-of-service is low.

Based on discussions of scenarios (1) and (2), the risk results for XST1 being OOS are equivalent to high wind/tornado events where both STs are available. This is because for scenario (1) the switchyard and both STs being unavailable is risk

equivalent to the case where both of the STs were available at the time of the event, due to the damage field caused by the tornado. For scenario (2), a situation where the damage has occurred to offsite power lines rendering them inoperable, there is little or no impact to risk results regardless of how many STs are available at the time of the event. However, as a risk reduction measure (but not credited in this analysis), the time of year for this activity will consider the weather data from National Oceanic and Atmospheric Administration (NOAA) and an appropriate time will be selected based upon low frequencies of weather events.

Internal Flood

Internal flooding is integrated into the CPNPP MOR 4A and is included in the base model analysis. Review of the results documented in Section 4.3 determined that internal flooding is a minor contributor to the increase of risk with XST1 out-of-service because differences in cutest results did not reveal impacts to cutsets with flood induced failures.

Seismic

For seismic events, CPNPP is considered to be in an area of low seismicity. However, the potential effects of the XST1 CTs will be considered for seismic events.

The CPNPP IPEEE seismic analysis (Reference 8.20) is the basis for the review of the XST1 impacts on seismic events. Per NUREG-1407 (Reference 8.21), CPNPP was identified as being in a region of low seismicity and classified as a reduced scope plant. As a reduced scope plant, the IPEEE Seismic analysis used a margin approach that assumed a LOOP and Very Small Break LOCA in a seismic event. Since the STs and both switchyards are not Category I seismic structures, they are assumed to be damaged (total failure) in the seismic event. In this case, maintenance on XST1 will have no affect on the consequences of a seismic event. However, assuming that one ST could survive the event, the recovery action would be impacted by the ability to recover power to the available ST's switchyard. Since the frequency of this scenario is small compared to a normal LOOP and the exposure time of the XST1 maintenance is short, the impact from seismic events on the two, one-time 14-day XST1 CTs is not risk significant. A sensitivity study was performed on the internal events model (Section 4.3) and results showed the impact to offsite power recovery from the ST being out-of-service was not risk significant.

Even so, an additional risk reduction measure will be completed prior to the start of a XST1 CT, namely a seismic walkdown on specified equipment. This walkdown is to identify obvious mounting or seismic interaction issues, such as loose parts or missing hardware. This walkdown will be done as an additional defense to identify and correct conditions that could impair equipment survivability during a seismic event. All four (4) EDGs and both TDAFWPs will be walked down based upon their importance to LOOP and SBO conditions.

Based on this analysis and the planned risk reduction measure, it is concluded that the extended CT for XST1 does not have a risk significant impact to the seismic events analysis.

Shutdown and Transition Risk

The proposed two, one-time 14-day CT for XST1 will be used to permit the continued operation of the CPNPP Units 1 and 2. Therefore by doing the work on XST1 at-power, transition and shutdown risk is avoided. This averted risk is not considered in calculating the impact of the at-power requested TS change.

If the extension is not granted, a dual Unit shutdown would be required to implement the XST1 modification. During that time only one AC offsite power source would be available to the two Units with their respective EDGs (as applicable by TS) and APDGs as the onsite AC emergency power source. Reduced offsite electric power availability has the effect of increasing shutdown and transition risk.

Evaluation of Other External Events

This Section provides a qualitative review of other external events on the requested two, one-time 14-day extensions to the ST CT. These assessments are performed for external floods, external fire, and other transportation and nearby facility accidents.

External Floods

This Section documents the analysis of external floods and their effects on the station. It was performed as part of the IPEEE for CPNPP (Reference 8.20), and addresses specifically the susceptibility of the safety related structures of the station to these conditions. Although there has been some growth in the area around CPNPP the insights and conclusions of the IPEEE work remain valid for this submittal, as no new flood sources have been identified and no changes have been noted to the existing analysis. This Section systematically considers the various factors that can contribute to the incidence of external flooding including historical data of river flooding, probable maximum precipitation (PMP), potential dam failures and other natural phenomena such as surges, hurricane, and tsunami. The STs are located south and west of the power plant at elevation 810 feet.

The records kept for the Brazos River from 1924 to 1975, around the CPNPP vicinity, indicate that the highest water level recorded was elevation 601.69 feet (May 27, 1957). This flood record is significantly lower than CPNPP site grade (elevation 810 feet).

The potential dam failures (seismically induced or otherwise) are not expected to affect CPNPP, as there are no impoundments other than small farm ponds on the Squaw Creek Reservoir catchment. Using ultraconservative assumptions, it can be calculated that in the case of domino type dam breaks of Morris Sheppard and Decordova Bend Dams the maximum water levels reached will be of the order of 700 feet elevation, 110 feet below CPNPP grade elevation.

A statistical method for estimating the largest rainfall likely to occur, as developed by Hershfield, has been used to determine the amount of precipitation to be felt potentially by the area. According to this, Rainbow, a nearby gauging

station, has a calculated PMP of 39.5 inches. However, the maximum precipitation likely to occur in 24 hours is 23.6 inches and the maximum recorded, from 1936-1971, is only 6.00 inches (from the CPNPP FSAR (Reference 8.3)).

Computation utilizing data for wind velocity, fetch length, and reservoir depth indicate that the wave run-up and wind tide at the dam and plant are about 4 and 5 feet. Corresponding elevations reached are 793.7 feet and 794.7 feet, respectively. All plant facilities are above the maximum wave run-up and setup elevation of 794.7 feet.

Due to the small size of Squaw Creek Reservoir there is minimum possibility of either surges or seiches occurring in the reservoir. Also, due to the fact that CPNPP is 300 miles away from the Gulf of Mexico and is over 800 feet above sea level, the probability of flooding due to a hurricane or tsunami is insignificant (Reference 8.20). In addition, the warm Texas climate is not conducive for any possibility of ice flooding.

The probable maximum flood (PMF) level due to the PMP was estimated to be 789.7 feet. The site drainage system is capable of functioning adequately during such a storm. Elevation reached due to wave run-up and wind tide was conservatively estimated to be 794.7 feet. All plant facilities are above this elevation. The effect of external events such as surges, tsunami, icing, etc., is insignificant.

The review of specific components located inside of Category I buildings, below the maximum elevation referenced in the above paragraph, indicates that there is no possibility of flooding these components and affecting their operability due to the PMF condition.

The above discussion details that the STs are not under a threat from external flooding, even at the worst conditions of probable maximum precipitation or potential dam failures. Therefore the contribution of external flooding event to the core damage frequency at CPNPP is not risk significant for the proposed configuration.

Fires External to the Plant

During the two, one-time 14-day CT extensions, there is a non-risk significant increase in risk to the plant associated with an external fires based on the discussion that follows. The potential vulnerability exists from brush or forest fires causing the loss of power from the remaining ST XST2 to the 345kV switchyard. The 345kV switchyard is supplied from the 345kV Parker1 and Parker2, 345kV Everman, 345kV Wolf Hollow, 345kV Venus, 345kV Comanche, and 345kV Decordova1 lines. The area inside the switchyard, between the yard and the STs and from the STs into the power plant contains minimal vegetation that would not affect offsite power. The rights-of-way for the two offsite power lines are routinely cleared of trees and significant vegetation. Hence any fires that were to occur are not expected to cause power disruptions due to the small amount of combustibles. Therefore the contribution of such events to the core damage frequency at CPNPP is concluded to be not risk significant for the proposed configuration.

Transportation & Nearby Facility Accidents

This analysis was performed as part of the IPEEE CPNPP (Reference 8.20). Although there has been some growth in the area around CPNPP and additional gas exploration within the Barnett Shale, the insights and conclusions of the IPEEE work remain valid for this submittal. Principal transportation routes extending to within 10 miles of the CPNPP site consist of two U.S. highways, one state highway, one railroad, and eleven air routes. No heavily traveled highways pass close to the site. All nearby roads have one or two lanes and have light traffic.

There are no airports within five miles of CPNPP. Based on data provided by the National Transportation Safety Board, an evaluation was performed to determine the probability of an aircraft impact accident. A statistical model using the causation probability (probability of an aircraft totally losing control) and the geometrical probability of random collision was employed in this analysis. This calculation provides the probability of an aircraft crashing into the CPNPP site as 1.91E-7 per year (Reference 8.3).

There are four pipelines traversing the site vicinity. One of them is a 26" crude oil line owned by West Texas Gulf. The other three are natural gas lines discussed in the Section below. At its closest approach, the crude oil pipeline is approximately 4000 feet from CPNPP (Reference 8.3). The only potential interaction of the pipeline with the safety related structures of CPNPP is from a break in the limited part of the pipeline that passes west of the safe shutdown impoundment (SSI). To prevent the spilled oil from reaching the SSI, three retaining ponds with a sufficient capacity to completely contain the maximum expected leakage have been built between the pipeline and SSI.

Drifting vapor clouds from the leaked oil do not pose any hazard to the normal operation or safety of the plant.

There are three natural gas pipelines traversing the site vicinity, two of these are 36" in diameter and the third is 6". The bounding case is considered to be the release of natural gas from a break in the 36" Lo-Vaca natural gas pipeline. Using conservative estimates, the vertical distance between the highest air intake at CPNPP and the lower flammability limit of the natural gas cloud was calculated to be 746 feet for a double-ended pipeline break, and 652 feet for a single-ended break (Reference 8.3). Thus no impact to plant operation would be expected.

An analysis of a postulated gas well located at 2,250 feet from the nearest plant structure showed that the distance from the structure to the lower flammability limit of the natural gas cloud is 1,050 feet (Reference 8.3). Industrial chemicals used in the day-to-day operation of the plant are controlled by detailed plant procedures. Also, a study conducted to evaluate the potential release of chlorine from onsite or offsite sources would not be expected to impact plant operation.

Other External Events Conclusion

From the above discussion, damage to the Category I building structures is not likely from external flooding, even at the worst conditions of probable maximum precipitation or potential dam failures. The potential maximum oil leak affecting the safety related structures of the station is unlikely due to physical barriers. In case of a gas line break the concentration of gas at any plant air intake is not expected to impact plant operation, i.e. it is well below the lower flammability limit. The land routes around the station are far away from the plant proper, and are lightly traveled as not to pose any type of hazard for CPNPP. In addition, the probability of an aircraft impact on CPNPP was estimated to be 1.91E-7 (Reference 8.3) and is considered not risk significant. The toxic chemicals used inside the plant are under the strict procedural controls which ensure that normal plant operation is not impacted. Also, the onsite or offsite storage/transportation of chlorine is not expected to pose any hazard to plant operation.

The area surrounding CPNPP was reviewed for other plant-specific external events that may affect the safety of the plant. With the exception of natural gas exploration, no industrial growth has occurred in the site vicinity. The only hazardous materials (excluding local gas stations and materials not directly related to CPNPP) regularly manufactured, stored, used, or transported in the vicinity of CPNPP are crude oil and natural gas transported through the pipelines described above. This review did not identify any other external events which might pose a significant threat to the plant.

Therefore, there is no significant increase in risk from external floods, external fires, transportation, or nearby facility accidents for the extended ST CT.

4.2.3 Summary of Analysis Results Compared to Acceptance Guidelines:

The results of the risk assessment for CDF, LERF, ΔCDF, ICCDP, ΔLERF, and ICLERP are summarized for internal events and internal flooding in Table 10. The corresponding risk significance guidelines defined in RG 1.174 (Reference 8.1) and RG 1.177 (Reference 8.2) are also in Table 6 and are compared to the risk assessment values.

Table 10: Comparison of Risk Assessment Results to Acceptance Guidelines

Unit	Output Parameters (XST1 OOS)	Value	Frequency	Acceptance Guidelines	Below Acceptance Guidelines
Unit 1	CDF_NEW	3.02E-06	Per Year	N/A	N/A
	ΔCDF	1.14E-08	Per Year	< 1.00E-06	Yes
	ICCDP	1.14E-08	Dimensionless	< 1.00E-06*	Yes
	LERF_NEW	2.15E-07	Per Year	N/A	N/A
	ΔLERF	5.35E-10	Per Year	< 1.00E-07	Yes
	ICLERP	5.35E-10	Dimensionless	< 1.00E-07*	Yes
Unit 2	CDF_NEW	3.01E-06	Per Year	N/A	N/A
	ΔCDF	1.14E-08	Per Year	< 1.00E-06	Yes
	ICCDP	1.14E-08	Dimensionless	< 1.00E-06*	Yes
	LERF_NEW	2.15E-07	Per Year	N/A	N/A
	ΔLERF	5.42E-10	Per Year	< 1.00E-07	Yes
	ICLERP	5.42E-10	Dimensionless	< 1.00E-07*	Yes

***For one-time TS changes the ICCDP and ICLERP acceptance criteria are <1.00E-05 and < 1.00E-06 given acceptable compensatory measures. The indicated values in the table are low compared to the permanent change criteria shown thus it was concluded that comparison to the permanent values was acceptable.**

NOTE: The numbers presented in the tables have been rounded from the actual values.

4.3 Avoidance of Risk Significant Plant Configurations and Uncertainty

Tier 2 of the three-tiered approach described in RG 1.177 for evaluating the risk associated with a proposed two, one-time 14-day CTs requires an examination of the need to impose additional restrictions when operating under the proposed CT in order to avoid risk significant equipment outage configurations and to understand the role uncertainty plays in application of the results of the risk assessment. The results of the risk assessment were analyzed to identify risk significant plant configurations and any appropriate risk reduction measures.

Analysis of Risk Assessment Results

Detailed analysis of the results of the risk assessment is necessary to identify previous assumptions and configurations that may have been overlooked or underestimated and have a potentially significant impact on the results of the evaluation. All internal events that impact total risk metrics (CDF, ΔCDF, and ICCDP) are to be re-analyzed for any conditions that may have been overlooked. For this detailed analysis the internal events results will be broken down into a review of the individual top cutsets and significant basic events.

Decomposition into Hazard Groups

The analysis to follow involved a detailed look at the internal events hazard group CDF assessment. Other hazard groups did not meet the requirements of RG 1.200 (Reference 8.12) for quantitative comparison as they were either qualitative or used models that do not meet the standards (risk insights only). The internal events CDF analysis was chosen because Table 10 showed LERF risk metrics to be minimally impacted by the extended

CTs on ST XST1. There were minor differences between Units 1 and 2 noted during the development of the CPNPP MOR. Unit 1 has installed steam generators (lowering steam generator tube rupture (SGTR) frequency) and is normally aligned to the 345kV switchyard with a higher number of redundant offsite power lines. These two features are offset due to the internal flooding analysis where Unit 1 has additional flood scenarios. The cumulative result is that Unit 1 has slightly higher CDF/LERF values than Unit 2. With XST1 OOS both Units are aligned to the 345kV switchyard via the in-service XST2 transformer, but due to internal flooding differences being more significant the above results are consistent with the modeled Unit differences.

Decomposition into Significant Accident Sequences or Cutsets and Basic Events

The purpose of this analysis was to determine the importance of individual contributors and assumptions for this proposed LAR. For this internal events assessment with the XST1 OOS, the results of the dominant initiators and cutsets for Unit 1 and Unit 2 were reviewed.

The results of the internal events analysis showed general plant transients that led to SBO conditions were the main contributor to ΔCDF. Reviewing the associated cutsets for Unit 1 and Unit 2, all of the scenarios involved a potential SBO with a combination of the failure of the in-service ST XST2 or associated components and the failure of the EDGs. The reason these dominant cutsets were important is that the SBO condition leads to an RCP seal LOCA without the ability for reactor coolant makeup (ECCS). In the XST1 base-case, following the RCP seal leak the batteries deplete in four hours and the combination of no ECCS makeup and no secondary heat removal would then lead directly to core damage. These scenarios do not take into account that the APDGs can be brought online after an SBO in accordance with SOP-614A/B (Reference 8.8) per the emergency operating procedure (EOP) network. Currently the CPNPP MOR credits the APDG only for LOOP initiators (i.e. INIT-X3) and is not modeled for other initiators that can lead to a SBO condition given other failures (i.e. INIT-T1); the latter scenarios are not in the top 95% CDF cutsets in the base model. Plant experience shows that the APDG can be loaded within an hour of the SBO. Given this time frame, the batteries would not have depleted and equipment for secondary heat removal (TDAFWPs, atmospheric relied valves (ARVs), and steam dumps) and ECCS makeup would be powered and available. Thus if the APDGs were credited the probability of these scenarios would be further reduced.

Review of the sequences determined that no new significant sequences were developed for the XST1 out-of-service case. It was determined that sequences associated with very small LOCAs due to non-LOOP initiators were most impacted by the single in-service ST XST2 configuration. The new cutsets results were the result of a loss of the in-service ST XST2 and both EDGs with the APDG not credited for non-LOOP initiators. Similar cutsets appear in the baseline files; however, the resulting cutset frequencies are lower as an additional failure of XST1 or its supporting equipment is required. Thus the non-risk significant impact of having a ST out-of-service was attributed to the low failure rates associated with the STs and their supporting equipment in conjunction with the capability of the EDGs. Crediting the APDGs for these scenarios would further reduce the quantitative risk results.

After reviewing the cutset files, the basic events importance measures were additionally reviewed for any further contributors. The results of the basic event analysis are much the same as the cutset review because XST2 (and associated

equipment) and both EDGs were again shown to be important components during the two, one-time 14-day CTs, along with their associated components, breakers, etc. However, the basic events associated with station service water (SSW) components were shown to also be important during the XST1 OOS. Therefore, the EDGs, XST2, SSW pumps and other important components' failure rates (TDAFWPs) will be addressed in sensitivity studies. Further, the restriction of maintenance on the SSW system was added as a risk reduction measure for the plant during the CT.

Assessment of Uncertainty

There are three primary categories of uncertainty associated with PRA model, as defined in NUREG-1855 (Reference 8.22) and the supporting EPRI guideline: parametric, modeling, and completeness uncertainty. Parametric uncertainties are inherent in a statistical model through the parameters of the distribution functions used to approximate real-world events. Completeness refers to a lack of detail in the model relative to the details that would be pertinent to the application. These types of uncertainty are addressed in this Section.

General model uncertainties have been examined and documented at length for the baseline model; however, those modeling uncertainties that may be affected by this configuration have been re-examined in the context of the application. Additionally, components that become more important under the proposed configuration have been examined for their impacts on uncertainty. The assessment of model uncertainties takes the form of sensitivity studies of the model and is discussed later.

Parametric Uncertainty

The parametric uncertainties associated with a PRA are relatively straight-forward, and can be examined using standard statistical error propagation techniques. To simplify this, UNCERT, part of the EPRI software package, has been used to automate much of the process. For the baseline model, this software was used to generate a Monte Carlo on the Unit 1 CDF and LERF cutset files to show that, in general, the calculated mean values were close enough to the point estimates for CDF and LERF to warrant use of the point estimates for applications and other evaluations. That analysis goes further to validate the Monte Carlo and discuss its uses and limitations. The baseline results for CDF and LERF indicate about a 5% deviation, which is within the acceptance criterion of NUREG-1855 (Reference 8.22) and EPRI 1016737 (Reference 8.23).

The state-of-knowledge (SOK) correlation, with respect to this analysis, is the relationship between events based on having a shared pool of data. While a failure rate itself has some uncertainty associated with it, it can be said that for similar components (e.g., two identical pumps), the uncertainty in the failure rate of one is no more or less than that of the other. In fact, these two components share the same probability distribution function and associated uncertainty as they are used together to estimate this data, and a Monte Carlo (or other sampling method) must be able to realize the correlation and not sample each of them independently. UNCERT and CAFTA, part of the EPRI software package, are integrated to address this. Rather than generating a probability for each basic event directly, UNCERT derives each basic event probability from the input parameters. Therefore, using a type code or variables in CAFTA instead of explicit values to define the parameters for the basic events addresses this correlation. In other words, UNCERT will calculate a basic event probability based on a particular set of input parameters from the type code, which will then apply to all basic events that use the type code with that set of parameters.

Performing an evaluation in this way represents the potential error in the point estimate of the metric associated with the variations in the basic event values about the uncertainty intervals of their distributions. The sampling method is effectively a sensitivity which accounts for uncertainty in every basic event, initiator, human action, etc., simultaneously. This is an essential way to characterize the overall uncertainty in the model.

For this application, the model has been modified to have XST1 out-of-service for an extended period of time. As added support for the study of uncertainty associated with this change, the Monte Carlo evaluations were performed on both the Unit 1 and Unit 2 cutset files for CDF and LERF, in order to verify that the differences between the mean values and point estimates has not been significantly impacted. The results (Figures 1, 2, 3, and 4) below were generated with 15,000 samples and include the probability distribution functions and the cumulative distribution functions. Table 11 shows the mean CDF and LERF deviations from the point estimates are about 4-6 percent and are within the acceptance criterion of 10 percent.

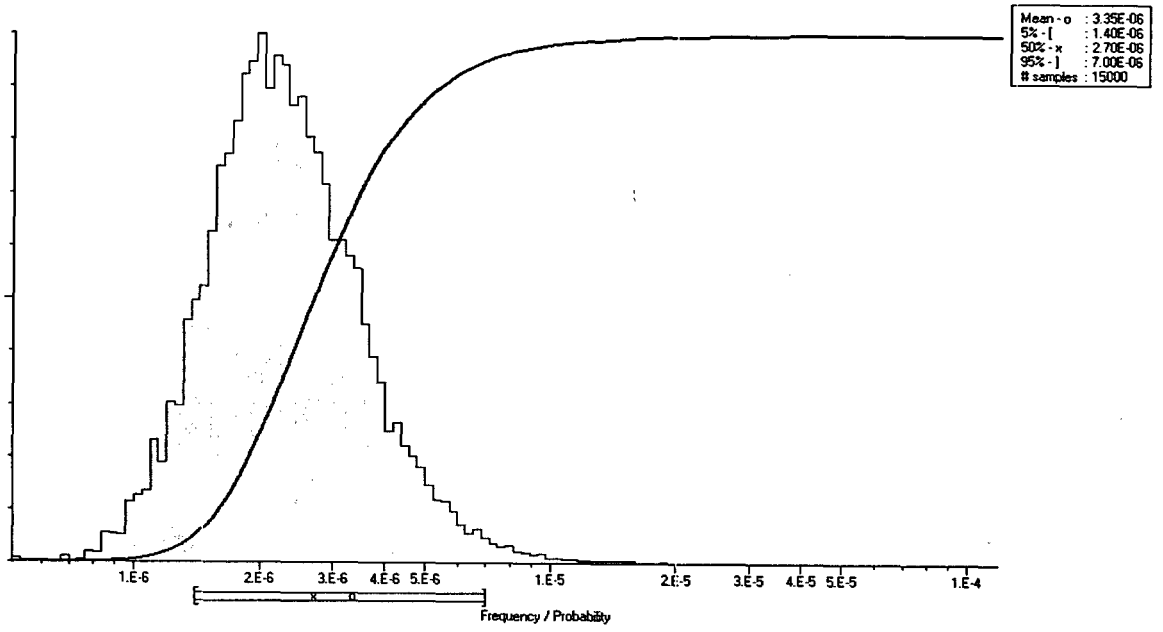

Figure 1: Unit 1 CDF Distributions

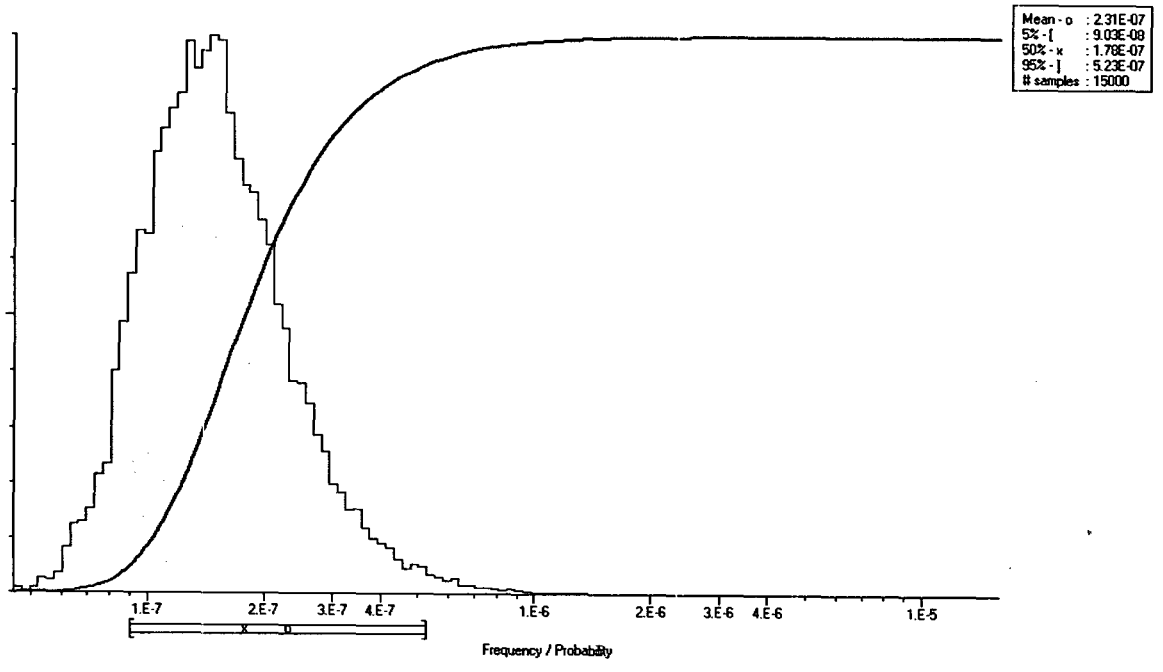

Figure 2: Unit 1 LERF Distributions

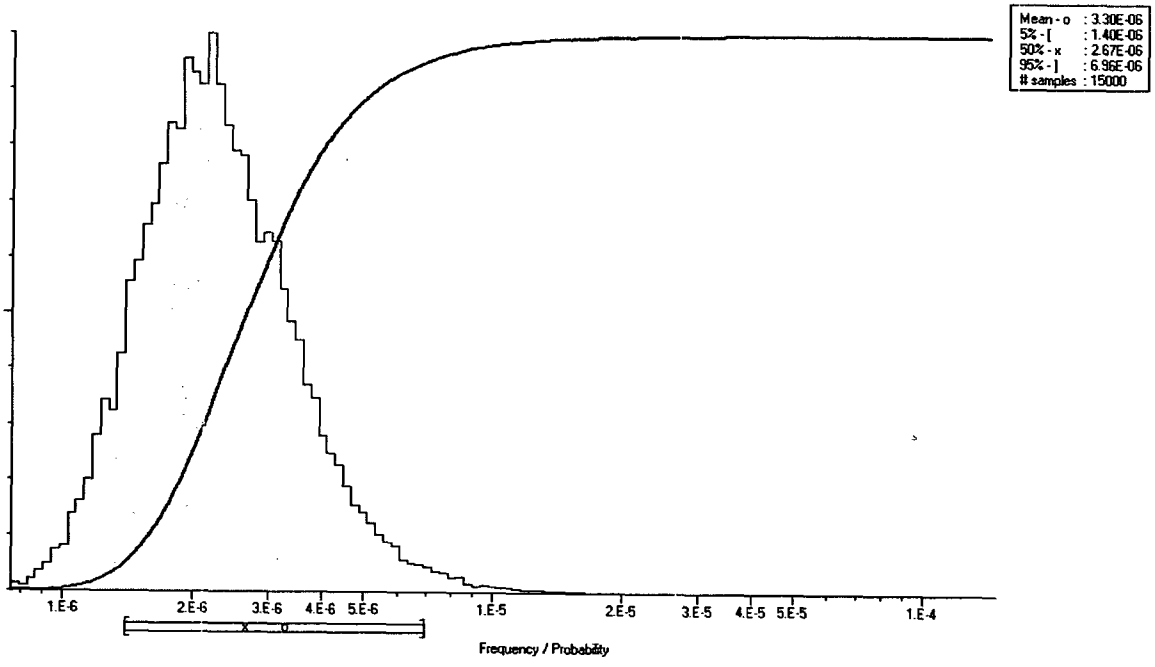

Figure 3: Unit 2 CDF Distributions

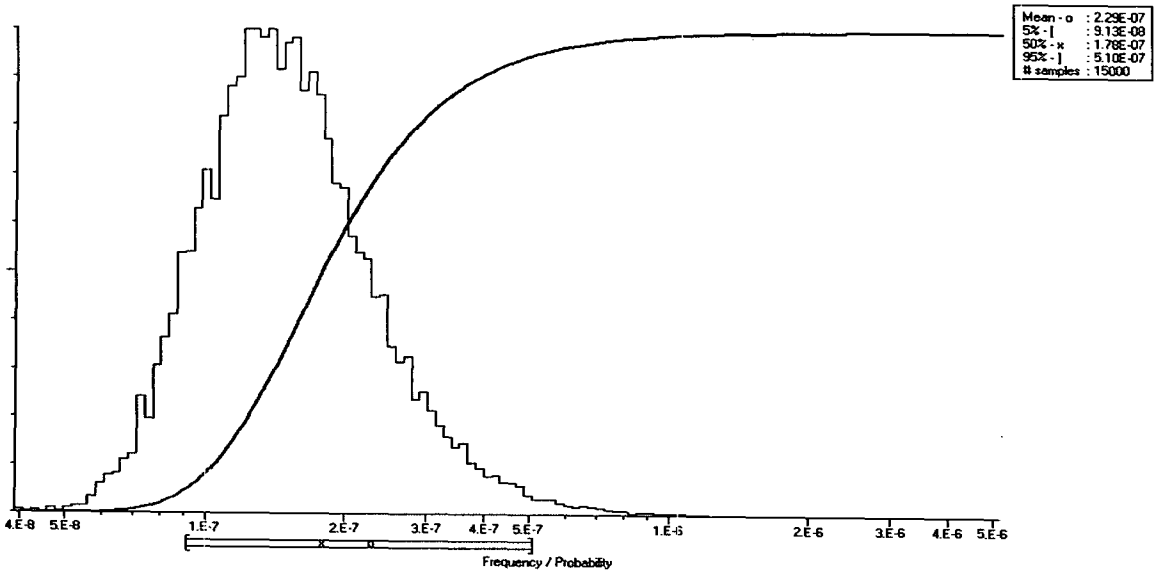

Figure 4: Unit 2 LERF Distributions

Table 11: Parametric Analysis Results

XST1 OOS	U1 CDF	U1 LERF	U2 CDF	U2 LERF
Point Estimate	**3.16E-06**	**2.21E-07**	**3.15E-06**	**2.21E-07**
Mean	**3.35E-06**	**2.31E-07**	**3.30E-06**	**2.29E-07**

NOTE: The numbers presented in the tables have been rounded from the actual values.

Completeness Uncertainty

For completeness, the proposed changes do not introduce any application-specific sources of uncertainty, and those for the baseline model have been minimized through the use of consensus modeling. The calculations include internal events and internal flood at power. The proposed configuration is only applicable at-power and other hazard groups (fire, external events) are unchanged from the Individual Plant Examinations.

Model Uncertainty

Throughout the analysis of the proposed two, one-time 14-day CTs there have been various assumptions and contributions that have been identified as warranting a sensitivity analyses. The individual analyses are necessary to address uncertainties regarding the assumptions in the PRA model. The following is a list of the sensitivity analyses that will be conducted:

1. Extended CT Duration (56 Days)
2. Modification of Offsite Power Non-Recovery Probabilities
3. Increase of Important Component Failure Probabilities
4. No Credit for APDG
5. Conservation of Test & Maintenance
6. Cumulative Assessment for All Sensitivities
7. Cumulative Assessment for All Sensitivities with No Test & Maintenance on Important Components

A summary of the results of these sensitivity cases will be discussed in the following Section, but a brief description of each sensitivity case is provided below. All sensitivities are applied to only the CT duration of the total New CDF/LERF calculations with exception of the conservation of test and maintenance, which is applied to the remaining duration of the new CDF/LERF calculations. The delta calculations (CDF and LERF) and the ICCDP/ICLERP calculations are compared against the baseline MOR Rev 4A results.

1. Extended CT Duration (56 days)

   This case study reflects the very low probability that work on XST1 will be extended due to various types of potential issues. Having work extended is considered a low probability since similar work was done previously on the recent XST2A installation. One new modification is the installation of a new disconnect switch. This case is used to demonstrate the increase in risk if the CT time were to be unexpectedly doubled.

2. Modification of Offsite Power Non-Recovery Probabilities

As discussed in this Section, the majority of the new cutsets were related to LOOP due to non-LOOP initiators. The CPNPP MOR (Revision 4A) has developed offsite power recoveries using a convolution method. This case study doubled the likelihood that offsite power recovery will NOT occur with XST1 out-of-service. The offsite power recoveries do not specifically contain the availability of XST1; thus this case study assumes an increase in difficulty for restoring offsite power with XST1 out-of-service and only XST2 in-service.

3. Increase of Important Component Failure Probabilities

Review of the risk results provided a list of components important to safety: XST2, EDGs, and SSWPs. Analysis of the cutsets provided insights to additional components important to safety for these scenarios: TDAFWPs, APDGs, and CCWPs (ECCS support). This case study doubled the likelihood of failure for these components. Since SSWPs and CCWPs are incorporated in the initiator logic for loss of service water (SW) and loss of circulating water (CW), the pump failure rates are also doubled in the initiator logic. One approach CPNPP uses to address the issue of reliability of these components during the two, one-time 14-day CTs for XST1 is to operate the EDGs, APDGs, and TDAFWPs in the two weeks prior to the start of the work window. The XST2 ST and SSWPs operate on a continuous basis, and the CCWPs are operated on a two week rotational basis. There is no negative trend in reliability associated with these components.

4. No Credit for APDGs

The installation of the APDGs is a recent plant modification; initially it was to be temporarily connected to the electrical system in support of outage, but the current design provides a permanent connection. Given the relatively recent installation of this equipment (late 2010), there is little industry operating experience with this component type. As such the MOR (Revision 4A) has a high failure rate for the APDGs. Given the lack of operating experience with the APDGs, this case study assumes the APDGs are not available.

5. Conservation of Test & Maintenance

During the two, one-time 14-day XST1 CTs CPNPP will not allow work on the following components: EDGs, APDGs, SSWPs, XST2, switchyards, and TDAFWPs to ensure their full availability and avoid increasing potential initiators. To account for any deferred testing and maintenance on components that will have activities suspended during the XST1 CTs, a baseline case will be run for the remainder of the year with all Test & Maintenance frequencies in PRA model increased by 10% (28 days/365 days = ~7.7% rounded up to 10%). The increase of all Test & Maintenance frequencies in the PRA model was chosen as conservativism. Additionally, because switchyard maintenance will also be suspended, the LOOP due to plant centered initiating events will also be increased by 10%. Below is the method by which this sensitivity will be calculated.

$$CDF\_New_{XST1\_Modified\_Base} = \left(\frac{T_{CT}}{T_{Year}}\right) * CDF_{XST1\_OOS} + \left(1 - \left(\frac{T_{CT}}{T_{Year}}\right)\right) * CDF_{Base\_Modified}$$

$$\Delta CDF_{XST1\_Modified\_Base} = CDF\_New_{XST1\_Modified\_Base} - CDF_{Base}$$

Where:

CDF_{Base} = baseline CDF

CDF_{XST2_OOS} = CDF for the XST2 out-of-service

$CDF_{Base\_Modified}$ = baseline average CDF with all T&M increased by 10% and the LOOP Plant Centered initiator increased by 10%.

T_{CT} = total days the XST1 transformer is to be out-of-service for this CT extension LAR, 28 days (e.g., two, 14-day CTs).

T_{Year} = time equivalent to one reactor year or 365 days of full power operation.

6. Cumulative Assessment for All Sensitivities

This case study is to demonstrate the cumulative effects of model uncertainty described in the above five case studies: extended CT duration (56 day), increased failure rate of offsite power non-recovery, increased failure rate of important components, no credit for the APDGs, and deferred maintenance.

7. Cumulative Assessment for All Sensitivities with No Test & Maintenance on Important Components

With the same inputs as case study 6, this case study is adjusted to take into account some of the risk management actions (RMAs) to be taken into account during the XST1 work window. Specifically, not allowing any Test & Maintenance to occur on the following components during the XST1 CT: TDAFWPs, EDGs, SSWPs, both 138kV and 345kV switchyards, and XST2 (the APDGs are not included since they are not credited in this case study).

Risk Mitigation Action Not Credited in the Analysis

Performing XST1 maintenance during the period from September 1st through March 31st when there is a significant reduction in weather events, demonstrated by Figures 5, 6, and 7 below (as provided by the NOAA website), will decrease the likelihood of certain initiating events (i.e. INIT-X3-WC). In addition, the transmission grid experiences less stress during this period compared to the summer months which makes consequential LOOPs less likely.

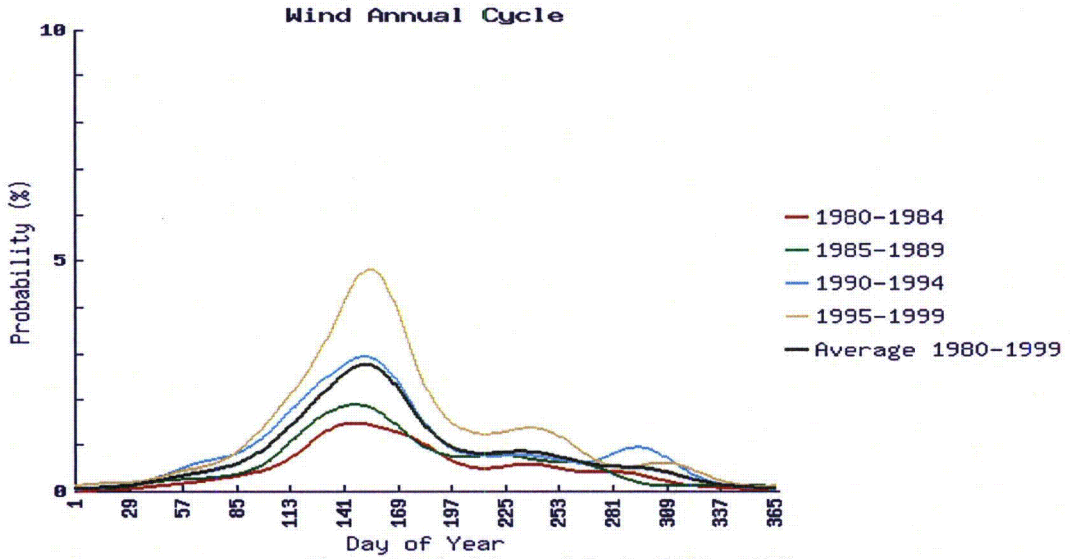

Figure 5: Wind Annual Cycle (1980 – 1999)

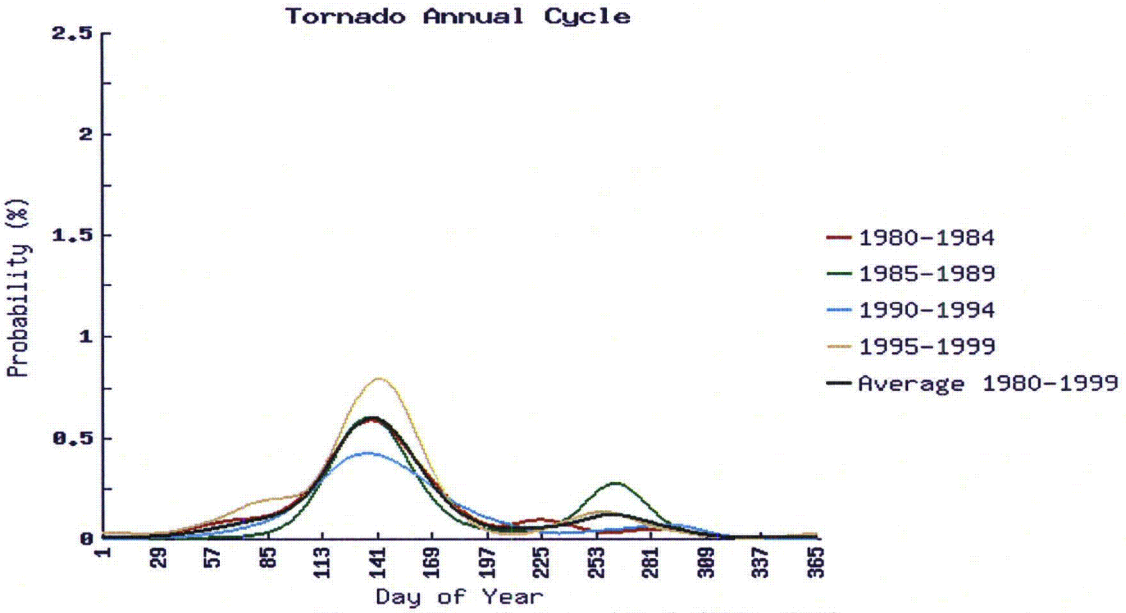

Figure 6: Tornado Annual Cycle (1980 – 1999)

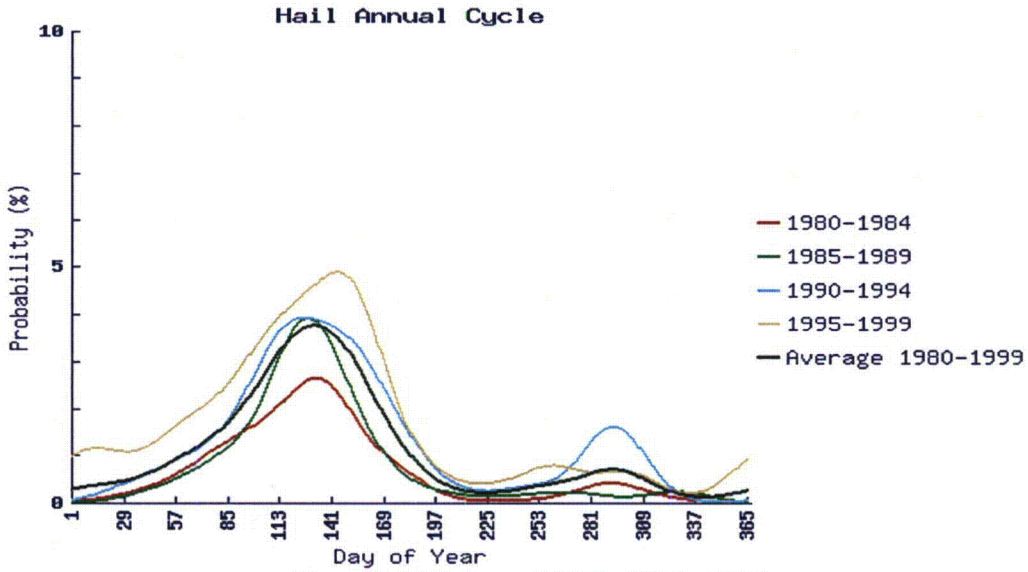

Figure 7: Hail Annual Cycle (1980 – 1999)

Summary of Sensitivity Studies

Tables 12 and 13 below summarize the CDF and LERF results for the seven sensitivity studies for both Units 1 and 2.

Table 12: CDF Sensitivities Results

Unit	Case Number	Case Study (XST1 OOS in all cases)	NEW CDF	DELTA CDF	ICCDP
Unit 1	1	Extended CT Duration (56 Days)	3.03E-06	2.27E-08	2.27E-08
	2	Modification of Offsite Power Non-Recovery Probabilities	3.05E-06	4.23E-08	4.23E-08
	3	Increase of Important Component Failure Probabilities	3.22E-06	2.15E-07	2.15E-07
	4	No Credit for APDGs	3.06E-06	4.93E-08	4.93E-08
	5	Conservation of Test and Maintenance*	3.07E-06	6.74E-08	6.74E-08
	6	Cumulative Assessment for All Sensitivities	3.86E-06	8.58E-07	8.58E-07
	7	Cumulative Assessment Crediting No T&M	3.69E-06	6.88E-07	6.88E-07
Unit 2	1	Extended CT Duration (56 Days)	3.02E-06	2.27E-08	2.27E-08
	2	Modification of Offsite Power Non-Recovery Probabilities	3.04E-06	4.22E-08	4.22E-08
	3	Increase of Important Component Failure Probabilities	3.21E-06	2.15E-07	2.15E-07
	4	No Credit for APDGs	3.05E-06	4.93E-08	4.93E-08
	5	Conservation of Test and Maintenance*	3.07E-06	6.74E-08	6.74E-08
	6	Cumulative Assessment for All Sensitivities	3.86E-06	8.57E-07	8.57E-07
	7	Cumulative Assessment Crediting No T&M	3.69E-06	6.88E-07	6.88E-07

NOTE: The numbers presented in the tables have been rounded from the actual values.

Table 13: LERF Sensitivities Results

Unit	Case Number	Case Study (XST1 OOS in All Cases)	NEW LERF	DELTA LERF	ICLERF
Unit 1	1	Extended CT Duration (56 Days)	2.15E-07	5.35E-10	5.35E-10
	2	Modification of Offsite Power Non-Recovery Probabilities	2.17E-07	2.78E-09	2.78E-09
	3	Increase of Important Component Failure Probabilities	2.22E-07	7.66E-09	7.66E-09
	4	No Credit for APDGs	2.18E-07	3.40E-09	3.40E-09
	5	Conservation of Test and Maintenance*	2.17E-07	2.35E-09	2.35E-09
	6	Cumulative Assessment for All Sensitivities	2.60E-07	4.51E-08	4.51E-08
	7	Cumulative Assessment Crediting No T&M	2.52E-07	3.78E-08	3.78E-08
Unit 2	1	Extended CT Duration (56 Days)	2.15E-07	5.42E-10	5.42E-10
	2	Modification of Offsite Power Non-Recovery Probabilities	2.17E-07	2.77E-09	2.77E-09
	3	Increase of Important Component Failure Probabilities	2.22E-07	7.66E-09	7.66E-09
	4	No Credit for APDGs	2.18E-07	3.40E-09	3.40E-09
	5	Conservation of Test and Maintenance*	2.17E-07	2.36E-09	2.36E-09
	6	Cumulative Assessment for All Sensitivities	2.59E-07	4.50E-08	4.50E-08
	7	Cumulative Assessment Crediting No T&M	2.52E-07	3.78E-08	3.78E-08

NOTE: The numbers presented in the tables have been rounded from the actual values.

All of the sensitivity results in Tables 12 and 13 have values that meet the guidance set forth in RG 1.174 (Reference 8.1) and RG 1.177 (Reference 8.2) for CDF, ΔCDF, ICCDP, LERF, ΔLERF, and ICLERP. Of particular interest is case study 6 with the cumulative uncertainty analysis that does not credit T&M being suspended. For this particular case assuming all uncertainties at once the ICCDP and ICLERP values remain below the thresholds required for a permanent change. Additionally the ICCDP and ICLERP values remain more than an order of magnitude below the 1.00E-05 and 1.00E-07 threshold for one-time changes (greater than two orders of magnitude for ICLERP). No other compensatory measures beyond those mentioned in each study were applied.

Risk Reduction Measures

The following is a list of the risk reduction/mitigation measures that are recommended to be performed during the 28 day XST1 CT (in two, one-time 14-day CT s) and additional discussion on the selection and implementation of the measures. These risk reduction measures were chosen to address various configuration risks and sensitivity analyses.

1. Restricted Access to and Suspension of Maintenance in the Switchyard:

   Access to both switchyards and relay houses will be controlled and posted, and all maintenance will be suspended for the duration of the CT on XST1.

   This risk reduction measure was selected based on the reliance of one ST during the 28 day CT (in two, one-time 14-day CT s). The measure is selected to deter any perturbations to the remaining ST power supply, 345kV switchyard, and any potential transmission grid or trip issues from the 138kV switchyard. Work in the switchyard is administratively controlled by the Operations Shift Manager who by plant procedure, STA-629 "Switchyard Control and Transmission Grid Interface," (Reference 8.5) has sole authority to grant access to the switchyard. By their authority; they will not allow any testing, maintenance or access to either switchyard; with the exception of normal operator visual inspection rounds. The STs, XST1 and XST2, are physically located in the protected area and not in the switchyard. Additionally, signs will be placed on both switchyards and relay houses noting the restriction of access, testing, and maintenance during this XST1 CT.

2. Suspension of Maintenance on the EDGs, APDGs, TDAFWPs, XST2, and SSWPs:

   The EDGs, APDGs, TDAFWPs, XST2, CCWPs, and SSWPs will have ALL testing and maintenance activities suspended for the duration of a one-time 14-day CT for XST1. Additionally, signs will be placed on the doorways to the equipment, or in the case of XST2 around the equipment, noting the restriction of testing and maintenance during this XST1 CT.

   This is to ensure the availability of these components for the entire duration of the CT.

3. Testing of EDGs, APDGs, and TDAFWPs Will Occur Within the Two (2) Weeks Prior to the Start of the XST1 CT:

   As seen in this analysis, the importance of the EDGs, APDGs, and the TDAFWPs to LOOP and SBO scenarios for this CT is significant. Therefore, to ensure the reliability of these components, they will be tested in the two weeks prior to the start of the XST1 CT.

4. Restriction on Transient Combustible Storage Along the XST2 Control and Power Cable Routing

   Both Unit 1 and 2 Transient Combustible safe zones identified in the fire analysis (TSN4-082) and the cable routing for the XST2 transformer will have additional restrictions relating to combustible storage during the extended CT durations. Implementing this risk reduction measure will reduce the fire risks that were identified for the transient combustible scenarios in the fire analysis.

5. Suspension of Hot Work Activities Near XST2 Power and Control Cabling

   All hot work activities along the routing associated with power and control cabling for XST2, the in-service ST, will be suspended during the XST1 CT. This is to reduce the risks associated with fires that could damage and thus disable the XST2 transformer cabling.

6. Roving Hourly Fire Watch Along Paths of XST2 Power and Control Cabling

   A roving hourly fire watch will be in effect during the 14-day XST1 CT along the path of the XST2 power and control cabling. This is an additional measure to monitor the area for fire risks that could damage and disable the XST2 transformer cabling.

7. Thermography of the Fixed Fire Sources

   In the two weeks prior to the start of the CT, a thermographic survey will be conducted on the two fixed sources in the safeguards switchgear room to verify no abnormalities exist. This is to reduce the likelihood of a fire ignition.

8. Selection of Time of Year Due to Weather Considerations

   Based upon the NOAA weather curve, a time in which severe weather is not expected will be selected for implementation of the XST1 CT. As shown in the weather curves, this time frame is September 1 through March 31. This planned timing will reduce the risk associated with high wind/tornados and weather challenges to the plant during the XST1 CT.

9. Seismic Walkdown for the EDGs and TDAFWPs

   The seismic walkdown will be completed prior to the XST1 CT to identify any issues that could impact the EDGs and TDAFWPs during a seismic event. These impacts include mounting or interactions issues including loose parts and missing hardware. This walkdown is for assurance that these components will meet their seismic design criteria in the event of a seismic incident.

4.4 Configuration Risk Management Program

Tier 3 requires a proceduralized process to assess the risk associated with both planned and unplanned work activities. 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 RG 1.177 (Reference 8.2), "...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 evaluations. Programs and procedures are in place at CPNPP which serve to address this objective.

CPNPP has a Configuration Risk Management program which has the characteristics of the Model Configuration Risk Management Program described in RG 1.177 (Reference 8.2) and which was previously approved for risk informed Technical Specifications. Its description has been incorporated into plant Technical Specifications. In addition, CPNPP has committed to NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (Reference 8.24). CPNPP will comply with Revision 4A of NUMARC 93-01 by December 2013.

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

CPNPP employs a conservative approach to at-power maintenance. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals and/or risk reduction actions. The assessment process further minimizes risk by restricting the number and combination of systems/trains allowed to be simultaneously unavailable for scheduled work. Unplanned or emergent work activities are factored into the plant's actual and projected condition, and the level of risk is evaluated. Based on the result of this evaluation, decisions pertaining to what action, if any, are required to achieve an acceptable level of risk (component restoration or invoking risk reduction measures) are made. The unplanned or emergent work activities are also evaluated to determine impact on planned activities and the effect the combinations would have on risk.

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

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

At CPNPP the procedures WCI-606 "Work Control Process" (Reference 8.25), WCI-202 "Maintenance Risk Assessment" (Reference 8.26), and WCI-203 "Weekly Surveillances/Work Scheduling" (Reference 8.27) are three of the controlling procedures for maintenance process. The CRMP program at CPNPP ensures that configuration risk has been managed prior to initiating any maintenance activity consistent with the requirements of 10CFR50.65(a)(4).

Currently CPNPP uses the Equipment Out-of-service (EOOS) software to perform online risk assessment. All PRA components are represented in EOOS with the ability to take one or multiple components out-of-service. After the activities have been added (i.e. component taken out-of-service) the model is re-quantified and the CDF and LERF are calculated. The risk is then compared to preset values and colors are assigned based on

these preset values. As the risk is increased the requirement for management approval is raised. External events are evaluated qualitatively to determine their impact on the configuration risk.

Summary of CRMP

This process is performed for all activities that affect PRA components, initiating events or recoveries. The Work Control Group uses the weekly schedule to calculate the plant risk for the week on an activity basis. The proposed CT would be planned and added to the weekly schedule and the risk for the activity would be calculated. The weekly risk assessment will be reviewed and appropriate management approval will be obtained. The process is the same for emergent activities as above. The risk is assessed prior to the emergent activity being worked. The risk is calculated and scheduled activities may be moved to a later date or equipment put back in-service to ensure that the risk is acceptable. Again the risk will be reviewed and appropriate management approval will be received. The above process meets the requirement of RG 1.177 Section 2.3.7 (Reference 8.2).

4.5 Summary of Technical Analysis

The analysis of the proposed extended CT consists of four main elements: (1) a traditional engineering analyses, (2) an evaluation of the adequacy of the CPNPP PRA and a risk assessment that shows an acceptable increase in risk (Tier 1), (3) avoidance of risk significant plant configurations (Tier 2), and (4) continued implementation of a Configuration Risk Management Program (CRMP) during the two, one-time 14-day extended Completion Times (Tier 3).

CPNPP has a robust design with the desired defense-in-depth design features (i.e., the ability to mitigate design basis accidents when a ST is out-of-service). Specifically, offsite and onsite power systems are diverse and redundant and meet regulatory requirements of GDC 17. While XST1 is out-of-service during the plant modification outages, XST2 has the capacity and capability to supply the required safety related loads of both Units. During the two, one-time, 14-day CTs for XST1, compensatory measures will be in place to assure safe shutdown and offsite power capability and availability. One measure, the APDGs, will provide an alternate power source to one safety related bus in Modes 3, 4, 5, and 6 to maintain the capability for safe shutdown and long term cooling of the Unit. Further, providing the capability for connection of a alternate ST XST1A to the 1E buses within the current TS CT of 72 hours is an improvement in plant design which eliminates the necessity to shutdown both Units if XST1 fails or requires maintenance that goes beyond the current TS CT of 72 hours. This change will improve the long-term reliability of the 138kV offsite circuit by providing connection to the ESF buses through XST1 or the alternate ST. Additionally, performing the work during two, 14-day CTs will provide a safe work environment for personnel safety and will not impact nuclear safety or the health and safety of the public.

For the 3-Tiered analysis of the XST1 28 day CT extension (in two 14-day CT periods) various factors were considered and reviewed to address the impact of the extension on the CPNPP PRA model. The analysis included a review of the PRA model quality, internal events, external events, sensitivity analyses, identified risk reduction measures, and a Configuration Risk Management Program as discussed in Section 4.2 through 4.4, respectively.

The Tier 1 analysis first addressed the model quality affirming requirements of Revision 2 of RG 1.200 (Reference 8.12) have been met, as discussed in Section 4.2 and Appendix 1. From this analysis it was determined that there is a high level of confidence in the PRA model and its ability to address the impacts of the XST1 CT extension. This conclusion is based the high quality of the model, its reflection of the plant systems and operation, and the peer review which concluded there are no gaps that would impact the results of the PRA analysis for this application. Individual evaluations of the two, one-time 14-day CTs for XST1 impact were performed for the internal events, high wind/tornado events, fire events, internal flood events, seismic events, and other external events. Based upon these evaluations, including quantitative and qualitative considerations, the risk results meet the guidance set forth in RG 1.174 (Reference 8.1) and RG 1.177 (Reference 8.2).

The resulting risk metrics in Table 14 show the impact of the XST1 extension on plant risk and how they compare to the regulatory acceptance criteria. From a Tier 2 consideration, this analysis has identified several risk reduction measures that increase the defense-in-depth strategy for the two, one-time 14-day XST1 CTs. These measures will be implemented to address initiating events, mitigation, uncertainties and equipment important to the XST1 CT, as detailed in Section 4.3.

Additionally, various uncertainties associated with this assessment that were identified in the PRA model were addressed and none were found to significantly affect the conclusions of this risk evaluation. These uncertainties are discussed in Section 4.3 include: two extended CT durations, increased offsite power non-recovery probabilities, increased failure rates of important components, no credit for the APDGs, and conservation of maintenance. The final two case studies examined the cumulative impact of these uncertainties. The sensitivity cases results were also within the guidance of RG 1.174 (Reference 8.1) and RG 1.177 (Reference 8.2).

Tier 3 requires a proceduralized process to assess the risk associated with both planned and unplanned work activities. 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 RG 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 evaluations. Programs and procedures are in place at CPNPP which serve to address this objective.

Based upon the comprehensive risk analysis presented in this evaluation, the XST1 CT being extended from 3 to 28 days (in two 14-day CT periods) will have minimal impact on the plant risk.

Table 14: Comparison of Risk Assessment Total Results to Acceptance Guidelines

Unit	Output Parameters (XST1 OOS)	Value	Frequency	Acceptance Guidelines	Below Acceptance Guidelines
Unit 1	CDF_NEW	3.02E-06	Per Year	N/A	N/A
	Delta CDF	1.14E-08	Per Year	< 1.00E-06	Yes
	ICCDP	1.14E-08	Dimensionless	< 1.00E-06	Yes
	LERF_NEW	2.15E-07	Per Year	N/A	N/A
	Delta LERF	5.35E-10	Per Year	< 1.00E-07	Yes
	ICLERP	5.35E-10	Dimensionless	< 1.00E-07	Yes
Unit 2	CDF_NEW	3.01E-06	Per Year	N/A	N/A
	Delta CDF	1.14E-08	Per Year	< 1.00E-06	Yes
	ICCDP	1.14E-08	Dimensionless	< 1.00E-06	Yes
	LERF_NEW	2.15E-07	Per Year	N/A	N/A
	Delta LERF	5.42E-10	Per Year	< 1.00E-07	Yes
	ICLERP	5.42E-10	Dimensionless	< 1.00E-07	Yes

NOTE: The numbers presented in the tables have been rounded from the actual values.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

Luminant Power is proposing a change to the Comanche Peak Nuclear Power Plant (CPNPP) Technical Specifications (TS) 3.8.1 entitled "AC Sources - Operating" to extend, on a one-time basis, two allowable Completion Times (CTs) of Required Action A.3 for one inoperable offsite circuit, from 72 hours to 14 days. This change is only applicable to startup transformer (ST) XST1 and will expire on March 31, 2014. This change is needed to 1) modify the XST1 138kV tower to add disconnects for a new alternate ST and replace the existing disconnects for XST1 and 2) to make final terminations to facilitate connection of ST XST1 or a alternate ST to the 1E buses. Installation of the cabling from XST1 and an alternate ST XST1A to two new 6.9kV transfer panels will allow alternate ST XST1A to be a fully installed alternate capable of being aligned to the 1E buses in place of XST1 within the original TS CT of 72 hours. Luminant 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:

5.1.1 Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

The proposed change will revise the CT for the loss of one offsite source from 72 hours to 14 days to allow two, one-time, 14-day CTs. The proposed two, one-time extensions of the CT for the loss of one offsite power circuit does not significantly increase the probability of an accident previously evaluated. The TS will continue to require equipment that will power safety related equipment necessary to perform any required safety function. The two, one-time extensions of the CT to 14 days does not affect the design of the STs, the interface of the STs with other plant systems, the operating characteristic of the STs, or the reliability of the STs.

Per Regulatory Guide (RG) 1.177 (Reference 8.2), the risk acceptance guideline presented in RG 1.174 (Reference 8.1) shows that Units 1 and 2 met all the risk acceptance guidelines for internal events and internal flooding for core damage frequency (CDF), ΔCDF, large early release frequency (LERF), ΔLERF, incremental conditional core damage probability (ICCDP), and incremental conditional large early release frequency (ICLERP). Additional risk analysis performed for external events (fire, seismic, high winds, etc.) provide assurance that the risk remains low.

The consequence of a LOOP event has been evaluated in the CPNPP Final Safety Analysis Report (Reference 8.3) and the Station Blackout evaluation. Increasing the CT for one offsite power source twice on a one-time basis from 72 hours to 14 days does not increase the consequences of a LOOP event nor change the evaluation of LOOP events.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

Response: No

The proposed change does not result in a change in the manner in which the electrical distribution subsystems provide plant protection. The proposed change will only affect the time allowed to restore the operability of the offsite power source through a ST. The proposed change does not affect the configuration, or operation of the plant. The proposed change to the CT will facilitate installation of a plant modification which will improve plant design and will eliminate the necessity to shut down both Units if XST1 fails or requires maintenance that goes beyond the current TS CT of 72 hours. This change will improve the long-term reliability of the 138kV offsite circuit ST which is common to both CPNPP Units.

There are no changes to the STs or the supporting systems operating characteristics or conditions. The change to the CT does not change any existing accident scenarios, nor create any new or different accident scenarios. In addition, the change does not impose any new or different requirements or eliminate any existing requirements. The change does not alter any of the assumptions made in the safety analysis.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

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

Response: No

The proposed change does not affect the acceptance criteria for any analyzed event nor is there a change to any safety limit. The proposed change does 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 affected by this change. The proposed change will not result in plant operation in a configuration outside the current design basis. The proposed activity only increases, for two, one-time pre-planned occurrences, the period when the plant may operate with one offsite power source. The margin of safety is maintained by maintaining the ability to safely shut down the plant and remove residual heat.

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

Based on the above evaluations, Luminant Power concludes that the proposed amendment present 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."

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."

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."

NRC Regulatory Guide 1.53, dated June 1973, titled "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems" (Reference 8.28).

NRC Regulatory Guide 1.62, dated October 1973, titled "Manual Initiation of Protective Actions" (Reference 8.29).

NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 8.30).

NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants." (Reference 8.32).

NRC Regulatory Guide 1.93, dated December 1974, titled "Availability of Electric Power Sources" (Reference 8.11). The current CT associated with inoperable AC power source(s) is 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 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."

NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988 (Reference 8.6).

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 (Reference 8.1).

NRC regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998 (Reference 8.2).
NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems" (Reference 8.32).

NRC Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies" (Reference 8.33).

Analysis

Only conformance with Regulatory Guide 1.93 is affected by this proposed change. According to RG 1.93, operation may continue with one inoperable offsite circuit for a period not to exceed 72 hours. If the proposed change is approved, CPNPP will continue to conform to this RG with the exception that the allowed CT for restoration of an offsite circuit will be increased, twice, on a one-time basis, to 14 days.

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

Luminant 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. Luminant Power has evaluated the proposed change and has determined that the change does 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 change meets 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

By letter dated June 29, 2012 the NRC issued Amendment No. 156, Docket Nos. 50-445 and 50-446, to Comanche Peak Nuclear Power Plant (CPNNP) Units 1 and 2 to relocate Surveillance Frequencies from Technical Specifications to a licensee-controlled program in accordance with Nuclear Energy Institute (NEI) 04-10, "Risk-Informed Technical Specifications Initiative 5b, Risk-Informed Methods for Control of Surveillance Frequencies." The amendment adopted the NRC-approved Technical Specifications Task Force (TSTF) traveler TSTF-425-A, Revision 3, "Relocate Surveillance Frequencies to Licensee Control - RITSTF (Risk-Informed TSTF) Initiative 5B." Much like the approved Amendment, this proposed submittal is also risk-informed (Reference 8.40).

The proposed change is similar to the following Nuclear Regulatory Commission (NRC) approved one-time, Completion Time (CT) extension precedent submittals below with one exception. The proposed two, one-time, 14-day, CT is not needed to perform maintenance on startup transformer (ST) XST2, but is needed to allow sufficient time to 1) modify the XST1 138kV tower to add disconnects for a new alternate ST and replace the existing disconnects for XST1 and 2) to make final terminations to facilitate connection of ST XST1 or a alternate ST to the 1E buses within the current Technical Specifications CT. After completion of this modification, should XST1 require maintenance or repair or catastrophic failure occurs, the alternate ST can be aligned to the 1E buses within the current CT of 72 hours. This change is needed to ensure the continued long-term reliability of the 138kV offsite circuit.

7.1 On May 27, 2009, the NRC issued Amendment No. 260, Docket No. 50-257, to Indian Point Nuclear Generating Unit No. 2 for a one-time extension to TS 3.8.1 from 72 hours to 144 hours. Specifically, the extension supported the replacement of a cooling oil pump on the station auxiliary transformer to restore operability of the associated offsite circuit (Reference 8.34).

7.2 Similar Amendment No. 239, Docket No. 50-219, was issued to Oyster Creek Generating Station on November 24, 2003, to delete the 30 day unavailability period restriction for occurrence of the specified 7 day allowed outage durations for the STs. During the allowed outage time of 7 days, the redundant Oyster Creek ST is required to be operable (Reference 8.35).

7.3 On October 10, 2003, the NRC issued Amendment Nos. 214 and 189, Docket Nos. 50-387 and 50-388, to Susquehanna Steam Electric Station (SSES) Units 1 and 2 regarding a one-time extension of the CT for TS 3.8.1, Action A.3, from 72 hours to 10 days. The one-time extension was needed for the planned replacement of ST No. 10 (Reference 8.36).

7.4 On October 9, 2001, the NRC issued Amendment No. 88, Docket Nos. 50-445 and 50-446, to Comanche Peak Nuclear Power Plant (CPNPP) Units 1 and 2 to extend the CT for TS 3.8.1 for restoration of an inoperable offsite circuit from 72 hours to 21 days. The request was to facilitate a one-time preventive maintenance outage on ST XST2 to ensure the continued long term reliability of XST2. (Reference 8.37).

7.5 By letter dated April 28, 2000 the NRC issued Amendment No. 206 to Facility Operating License No. DPR-51 and Amendment No. 215 to facility Operating License No. NPF-6, Docket Nos. 50-373 and 50-368, for Arkansas Nuclear One (ANO), Units 1 and 2, respectively. The amendment provided a 30-day allowed outage time for offsite ST 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. (Reference 8.38)

7.6 By letter dated October 15, 2010, the NRC issued Amendment Nos. 224 and 217, Docket Nos. 50-361 and 50-362 to San Onofre Nuclear Generating Station Units 2 and 3. The amendment requested a one-time extension per train to the CT from 72 hours to 10 days. (Reference 8.39)

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," Revision 2, May 2011.

8.2 NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 1, May 2011.

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

8.4 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.

8.5 STA-629, "Switchyard Control and Transmission Grid Interface," Comanche Peak Nuclear Power Plant, Revision 7.

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

8.7 NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives addressing Station Blackout at Light Water Reactors.

8.8 SOP-614A/B, "Alternate Power Generator Operation," Comanche Peak Nuclear Power Plant Procedure, Revision 12.

8.9 INPO IER L1 11-4, "Near-Term Actions to Address the Effects of an Extended Loss of All AC Power in Response to the Fukushima Daiichi Event," Dated August 1, 2011 and Revised September 29, 2011.

8.10 Letter from Rafael Flores (Comanche Peak Nuclear Power Plant) to Ms. Kim Maza (Institute of Nuclear Power Operations), "Response to IER No. L1 11-4, 'INPO IER L1 11-4, "Near-Term Actions to Address the Effects of an Extended Loss of All AC Power in Response to the Fukushima Daiichi Event,'" dated January 25, 2012.

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

8.12 Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009.

8.13 ER-EA-005, "Individual Plant Examination of External Events: Fire Evaluation, Comanche Peak Steam Electric Station," April 1995.

8.14 EPRI Report Project 3385-01, "Fire Risk Analysis Implementation Guide," January 1994.

8.15 CPNPP Fire Protection Report Revision 29.

8.16 DBD-ME-260, "Residual Heat Removal System," Comanche Peak Nuclear Power Plant, Revision 26.

8.17 SOP- 102, "Residual Heat Removal System," Comanche Peak Nuclear Power Plant, Revision 18.

8.18 NUREG/CR-6850, "Fire PRA Methodology for Nuclear Power Facilities," September 2005.

8.19 ER-EA-004, "Individual Plant Examination of External Events: Tornado Risk Assessment, Comanche Peak Steam Electric Station," April 1995.

8.20 ER-EA-008, "IPEEE for Severe Accident Vulnerabilities," June 1995.

8.21 NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Sever Accident Vulnerabilities," June 1991.

8.22 NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Volume 1.

8.23 EPRI 1016737; "Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments," Feb. 2008.

8.24 NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness Of Maintenance At Nuclear Power Plants," Revision 4A, April 2012.

8.25 WCI-606, "Work Control Process," Comanche Peak Nuclear Power Plant Procedure, Revision 14.

8.26 WCI-202, "Maintenance Risk Assessment," Comanche Peak Nuclear Power Plant Procedure, Revision 0.

8.27 WCI-203, "Weekly Surveillances Work Scheduling," Comanche Peak Nuclear Power Plant Procedure, Revision 27.

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

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

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

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

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

8.34 Letter to Vice President, Nuclear Operations of Entergy Nuclear Operations, Inc. (Indian Point Nuclear Generating Unit No. 2) from John Pl Boska (USNRC) dated May 27, 2009, "Issuance of Amendment Re: Allowable Completion Time for Offsite Electrical Power Sources (TAC NO. MD9648)."

8.35 Letter from Peter S. Tam (NRC) to John L Skolds (AmerGen Energy Company) dated November 24, 2003, "Oyster Creek Nuclear Generating Station – Issuance of Amendment Re: Startup Transformer and Emergency Diesel Generator Unavailability Periods (TAC No. MB9144)."

8.36 Letter to Mr. Bryce L. Shriver (PPL Susquehanna, LLC) from Richard V. Guzman (USNRC) dated October 10, 2003, "Susquehanna Steam Electric Station, Units 1 and 2 – Issuance of Amendments Re: Extended Outage Time for Offsite Power-Single Occurrence (TAC NOS. MB9903 and MB9904)."

8.37 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.

8.38 Letter to Mr. Craig G. Anderson (Entergy Operations, Inc.) from M. Christopher Nolan (USNRC) 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)."

8.39 Letter to Mr. James J. Shepard (Southern California Edison Company) from James R. Hall (USNRC) dated October 15, 2010, "San Onofre Nuclear Generating Station Units 2 and 3 - Issuance of Amendments Revising Technical Specification 3.8.1, 'AC Sources – Operating' (TAC Nos. ME4508 and ME4509)."

8.40 Letter to Mr. Flores (Comanche Peak Nuclear Power Plant) from Balwant K. Singal (USNRC) dated June 29, 2012, "Comanche Peak Nuclear Power Plant, Units 1 and 2 – Issuance of Amendments Re: Relocation Surveillance Frequencies from the Technical Specifications to a Licensee-Controlled Document," Amendment No. 156. (TAC Nos. ME6789 and ME6790).

8.41 ASME RA-Sb-2005 ADDENDA to ASME RA-S-2002, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications," dated December 30, 2005.

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8.43 ECE 2.15, "Risk and Reliability Functions," Comanche Peak Nuclear Power Plant Procedure.

8.44 R&R-PN-041, "Sensitivity and Uncertainty," Comanche Peak Nuclear Power Plant Procedure, Revision 4A.

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8.47 ECE 2.15 Evaluation Log # 212, "IPEEE Seismic Analysis Applicability to Revision 4A Model Results," July 2012, Revision 0.

8.48 EPRI Report, "Fire Events Database for U.S. Nuclear Power Plants," NSAC-178L, Final Report, June 1992.

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APPENDIX A to TXX-12084

CPNPP PRA MODEL SCOPE AND QUALITY

PRA Model

The following addresses the assessment of technical adequacy of the probabilistic risk assessment (PRA) used to support the proposed one-time Technical Specification (TS) change to extend the startup transformer (ST) XST1 Completion Time (CT) to 28 days (in two 14-day CT periods). The guidance in Regulatory Guide 1.200 (Reference 8.12) has been used to demonstrate the technical adequacy of the parts of the PRA model used for this application. The Comanche Peak Nuclear Power Plant (CPNPP) PRA model used for this application is the Level 1Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) analysis of internal events, including internal flood, for at-power operation, Revision 4A.

Adequacy of the PRA - Scope and Level of Detail of the PRA Model

The CPNPP PRA model of record (MOR) was recently upgraded. The model upgrade addressed Level 1 and LERF analysis of internal events, including internal flood, for at-power operation. This upgrade was initially embodied in the CPNPP MOR Revision 4 which was completed in early 2011. The model was then submitted to a Pressurized Water Reactor Owners Group (PWROG) full scope peer review in March 2011. The peer review was performed against the requirements of the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) PRA standard (Reference 8.41) and any clarifications and qualifications provided in the Nuclear Regulatory Commission (NRC) endorsement of the standard contained in Revision 2 to Regulatory Guide (RG) 1.200 (Reference 8.12). Further, the peer review was performed using the process defined in Nuclear Energy Institute (NEI) 05-04 (Reference 8.42). The Revision 4 model was further revised, in part, to incorporate the model changes in response to the Peer Review Findings & Observations (F&O) and issued as Revision 4A. Thus, the current MOR for CPNPP is PRA Model Revision 4A.

The PWROG peer review of the CPNPP PRA Model Revision 4 and the responses thereto embodied in Revision 4A provide a high degree of assurance of the technical adequacy of the CPNPP PRA model to support the implementation of this two, one-time 14-day CTs concerning ST XST1 License Amendment Request (LAR). The conclusions documented in the peer review showed that the CPNPP MOR 4 meets ASME Capability Category II or better for nearly all of the Supporting Requirements. After F&Os were fully addressed through post-peer review model work and documentation, as reflected in CPNPP MOR 4A, all Supporting Requirements judged to have significance to this LAR now meet Capability Category II or better. The F&Os and their disposition, including Category I exceptions, are provided in Table 1 of this Appendix below.

Model Development

The CPNPP PRA model was developed using programmatic controls to help assure that the model reflected the as-built and as-operated plant. This process included gathering detailed as-built and as-operated plant information and operating plant data, discussions with system engineers and operators, and plant walkdowns. The continuing PRA maintenance and update process ensures that the CPNPP PRA model remains an accurate reflection of the as-built and as-operated plant. These processes are defined in the governing procedure ECE 2.15 (Reference 8.43), and subordinate implementation guidelines. The procedure and guidelines define the processes for implementing regularly scheduled and interim PRA model updates, and for tracking issues identified as potentially affecting the PRA model (e.g., due to changes in the plant, errors or limitations identified in the model, software, industry operating experience, etc). As of the date of the submittal of this LAR, there are no plant changes of significance that have not been incorporated into the PRA model.

PRA Model Maintenance and Update

Luminant employs a programmatic approach to establish and maintain the technical adequacy and plant fidelity of the PRA model. This approach includes a detailed PRA maintenance and update process in conjunction with the use of self-assessments and independent peer reviews.

In addition, requirements are established for controlling the model and associated computer files. Controls provide for retention of documentation and electronic storage for PRA model and basis information, updates, and applications.

Further, guidelines are provided for updating the full power, internal events PRA model for CPNPP. Regularly planned PRA model updates nominally occur on an approximate 5-year cycle; longer intervals may be justified if it can be shown that the PRA continues to adequately represent the as-built, and as-operated plant. CPNPP completed the Revision 4A MOR upgrade in 2011; this was a comprehensive upgrade and included previously incorporated plant modifications.

Consistency with Applicable PRA Standards

As indicated above, a full scope peer review of the CPNPP PRA Model Revision 4 was completed by the PWROG in March 2011 against the requirements of the ASME/ANS PRA standard (Reference 8.41) and any clarifications and qualifications provided in the NRC endorsement of the standard contained in Revision 2 to Regulatory Guide (RG) 1.200 (Reference 8.12). The peer review of CPNPP MOR 4 and the subsequent revision, CPNPP MOR 4A, applied standards set forth in ASME/ANS RA-Sa-2009 Parts 1, 2, and 3. The results of the peer review demonstrated that the model is consistent with the standard and technically adequate to support the proposed request for two, one-time 14-day CTs for ST XST1 at CPNPP.

Identification of Key Assumptions and Approximations

For the CPNPP PRA MOR Revision 4A, key assumptions and approximations were identified and documented in the various notebooks. In addition, modeling uncertainties associated with scope or level of detail (modeling choices) for the baseline PRA are documented and validated in the respective notebooks. For example, the individual system models were analyzed with respect to the assumptions documented in the system notebooks to understand the impacts of those assumptions on the overall model. Finally, a comprehensive uncertainty analysis was done using a consensus methodology developed by Electric Power Research Institute (EPRI) and documented in Project Notebook R&R-PN-041 (Reference 8.44). A brief discussion of the analyses is provided below.

As part of the PRA MOR Revision 4A development, a wide range of generic contributors to modeling uncertainties were examined in order to aid in the decision making process of potential applications. Each area of uncertainty is generally related to certain key assumptions and approximations associated with the model and each was characterized through sensitivity studies. The sensitivity studies provide a mechanism for meeting the ASME high level requirements and provide a better understanding of the model that will ultimately be used in the decision-making process supporting risk informed applications.

These contributors included: Generic Sources of Uncertainty (e.g., initiating event frequencies such as Loss of Offsite Power (LOOP) and Loss of Coolant Accident (LOCA)), Support Systems Initiating Events and Recovery, Unit Cross-Tie Recovery, Overfill Recovery, LOOP Recoveries,

Battery Life, Test and Maintenance, Human Reliability, Reactor Coolant Pump (RCP) Seal LOCA, Consequential LOOP, Room Cooling, Sump Plugging, Power Operated Relief Valve (PORV) Operation/Pressure Relief Failure, Common Cause Failures, and Interfacing System Loss of Coolant Accident (ISLOCA) Failures. In addition, Major Component Importance Measures (i.e., Diesel Generators, 6.9 kilovolt (kV) Components, and Cooling Water Components) were also examined. For these sensitivity studies, factors of 2 and 10 were typically used, although other factors were used where appropriate to gain the best insight. The results of these studies were tabulated and provide a summary source of information that can be used to gain insights that affect these areas of the plant model. A more detailed discussion of uncertainty related to this LAR is provided in Section 4.3.

Resolution of Peer Review Findings and Observations

The results of the PWROG peer review of the CPNPP PRA Model Revision 4 (Reference 8.45) showed 21 Findings and 55 Observations/Suggestions and 4 Best Practices. The F&O Findings were resolved through model and/or documentation changes. When these were completed, the model was quantified and all the affected project notebooks were updated. The peer review Findings and their resolutions are presented in Table 1 below.

IPEEE Fire and Wind Analyses

CPNPP completed fire and wind PRA studies to address these external events as part of the Individual Plant Examination of External Events (IPEEE). The studies have not been updated since that time. However, these analyses were reviewed and deemed to be acceptable for the purpose of assessing the impact on CDF from the proposed extended XST1 CT.

Since the completion of the IPEEE, there have been changes to the plant configuration and procedures. These changes would tend to lower the IPEEE fire and wind results as they have been shown to lower the values of CDF and LERF for internal events and internal flooding. Further, for this submittal, a walkdown was performed to determine cable routing from the STs to the four (4) safety-related 6.9kV switchgear units.

Similarly, based on walkdowns, no new tornado (high winds) missile impacts were identified due to changes in plant configurations. An evaluation, CPNPP ECE 2.15, Log # 211 (Reference 8.46), reviewed recent national tornado data and hazard analysis methodology and determined that the IPEEE still bounds expected tornado hazard for CPNPP. The evaluation concluded, based on the updated tornado hazard calculation and the Revision 4A model, that the IPEEE tornado related insights can still be considered valid for qualitative analysis. Therefore, the IPEEE fire and wind assumptions and analyses can be used to reassess the XST1 two, one-time 14-day CTs extension request as described in this submittal.

IPEEE Seismic Margin Analysis

It is noted that the seismic PRA margin analysis was created in support of the IPEEE. The United States Geological Survey (USGS) updated seismic hazard maps and EPRI seismic hazard results for CPNPP were reviewed in CPNPP ECE 2.15 Evaluation Log # 212 (Reference 8.47). The evaluation determined that the seismic hazard at CPNPP has not substantially changed since the IPEEE (Reference 8.47). Therefore, the conclusions from the IPEEE stating that there are no plant-specific vulnerabilities to seismic events at CPNPP remain conservative and bound the expected current day seismic risk impacts for CPNPP.

Assessment of PRA Quality

To ensure a high quality PRA and to provide quality control to the update process, a peer review was conducted on the CPNPP PRA MOR (Revision 4). The F&O Findings and their dispositions, including Category I exceptions, are provided in Table 1 below. It should be noted that CPNPP recently submitted a license amendment request for Risk Informed Technical Specification Initiative 5B and received an approved NRC SER. This CPNPP LAR includes the same F&O items as those approved in the NRC SER (Reference 8.40).

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
1-7 (including Suggestion 6-5)	IFSN-A16 IFSN-A14	SW flood sources in the diesel generator rooms (1-084-SW and 1-085-SW), and as a result the areas themselves, were screened in part based on the availability of alarms indicating a pipe failure and the ability to isolate the break before the SW system would be lost resulting in an initiating event. However, credit for the operator isolation is not noted as part of the basis for screening the source and area in R&R-PN-021 Table 4.5-2. Assessment: Cat I is MET	In the original analysis, it was determined that a loss of a single Service Water (SW) train would cause a Technical Specification (TS) immediate plant shutdown due to the loss of an Charging pump. It was determined that there were viable operator actions to isolate the diesel generator SW without affecting the Charging pumps. After further consultation with plant licensed operators it was later concluded that the loss of a Charging pump function did not result in an immediate TS plant shutdown. The use of operator actions to screen these flood scenarios therefore was not necessary and the scenarios were required to be screened by other criteria. These rooms are now currently screened by the criteria that they do not cause an initiating event. Table 4.5-2 of PN-021 [CPNPP Internal Flood Analysis] was revised to state that a loss of one emergency diesel generator and a single train of service water (SW) do not cause an immediate plant shutdown. The SW pipe break for the scenarios in question is assumed to occur in the diesel room. The flood in the diesel room will propagate outside the safeguards building and not cause a plant trip. No further analysis was conducted on these specific operator actions in question. Cat II or better based on this resolution

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
1-10	HR-E3 HR-E4 HR-G5 HR-I1	Documentation of past operator interviews was provided. The manner in which these interviews were performed is not documented so it is not clear that detailed talkthroughs were performed and in any case this information is from the 2003 time frame. This information was supplemented in the latest revision with specific questions to operations personnel that are documented in R&R-PN-020 Attachment 4. However, the documentation of the operator interviews is not judged by the review team to be sufficient to support peer review and model updates. Assessment: Cat II or better MET	Additional Operator interviews were performed as follows: The modeled Human Interactions fall into three general categories of response: 1) simple alarm response, 2) plant trip response using EOP/EOS procedures (i.e. typical response), and 3) response following loss of function using FR / ECA procedures. Several HIs from each category were selected as representative of the category. Standard briefing sheets and open ended response areas were prepared with the goal of confirming the response model (including timing) for modeled scenarios and that the PRA analyst's interpretation of procedures was consistent with plant observations and training procedures. The briefing packages were used to capture the interview observations of three Operations Unit Supervisors (i.e. 3 crews). For each modeled action, the Unit Supervisors stepped through the associated procedures, including timing estimates and crew dynamics where appropriate. The Operations Support Supervisor (current SRO) also provided "EOPs for Engineers" training for the PRA analysts. This training covered EOP usage and operations protocols including training standards, timing standards, etc. The Operations Support Supervisor also provided response and timing information for a number of specific modeled actions. The results from these interviews were consistent with the modeled HFEs and did not require significant changes to any HEPs. Cat II or better MET

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
1-11	HR-G7 HR-H3 QU-C2	The top 7 HFE combinations appearing in the quantification results were reviewed. Three had incorrect ordering of the independent failures (i.e., the wrong HFE in the combination was assigned as the independent failure) and one had an incorrect assignment of complete dependence. An example of combinations with the incorrect assignment of the independent failure is TLXHICOMB106. In this combination, the first event should be TLXHISGPSLLY based on review of the event tree. However, TLXHICOND45Y is treated as the independent event in calculating the combined HEP. The correct sequencing of the events would lead to a different outcome for the joint probability. In addition, one of the reviewed combinations revealed that complete dependence was assigned for actions with an intervening success. For example, HFEs TLXHIHPR13SY, Failure to Align High Pressure Recirculation, and TLXHIEOS13SY, Failure to align Low Pressure Recirculation are assigned complete dependence (TLXHICOMB111). However, in the context of the sequence, there is an intervening success in this sequence (Secondary Depressurization) which would result in the HFEs being assessed as independent. Assessment: HR-G7 was NOT MET	The HRA dependency analysis was completely revised. An updated version of the HRA Calculator® allowed intervening successes and local delay timings to be adjusted so as to correctly assign the independent failure. All HFEs were reviewed to insure that a consistent definition of T_0 was used and that cues were appropriate for the accident sequence context where the combination appears. As stated previously, delay times for individual actions within a combination were locally adjusted when necessary to provide the correct ordering of actions for the dependency analysis. All combinations were reviewed to confirm that the correct HFE had been designated as the independent event. All combinations were reviewed to verify that intervening successes had been properly identified. Cat II or better based on this resolution

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
1-12	QU-D4 LE-F2	R&R-PN-035 Section 5.8 compares the total LERF for CPNPP with several other Large Dry Containment 4-loop PWRs. However, there is no comparison at the level of significant contributors or plant damage states. Without the comparison of contributor information, it is not really possible to determine how similar the LERF results are to other plants and whether excessive conservatisms have skewed the results. For example, the contribution to LERF from early containment failure is significantly higher than usually found for large dry containments. This may be valid for CPNPP and based on some plant-specific design feature, but it does not appear that there was consideration of the possibility that this is driven by modeling assumptions rather than design. Assessment: LE-F2 was NOT MET	A comparison of the LERF results to plants of similar design at the significant contributor and PDS levels was added to R&R-PN-035 [CPNPP Level 2 Fault Tree Analysis] and RXE-LA-CPX/0-105 [CPNPP PRA Level 2]. This comparison shows that the CPNPP LERF results are reasonable based on plant specific features and thermal hydraulic analysis. Cat II or better based on this resolution
1-16	HR-I3	R&R-PN-020 [Human Reliability Analysis] Section 3 is titled "Assumptions and Sources of Uncertainty." However, those assumptions that are sources of uncertainty are not clearly identified. Assessment: Cat I - III MET	PN-020, §3.0 has been subdivided into 3 subsections dealing with modeling choices, assumptions, and source of uncertainty. The sources of uncertainty have been verified to be characterized under QU-F4 as described in PN-041 [CPNPP Uncertainty Analysis]. Cat I - III MET

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
2-8	SC-A6	For SGTR, there appears to be no consideration of the case where an MSSV opens following the SGTR (not as a result of overfill) and sticks open, allowing the SG to depressurize. Assessment: Cat I - III MET	Additional plant specific thermal-hydraulic analysis performed for SGTR case with stuck open MSSV. No changes to success criteria or model logic were necessary. Cat I - III MET
2-12	AS-A4 AS-A5 AS-A7 AS-A10 AS-C2	The model uses a simple, two sequence event tree for all transient groups. This is not fundamentally a problem, since it is possible to build the event-specific plant response into the sequence top logic. However, in order to do that, the event-specific progression needs to be discussed in detail, the possible sequences defined, and each possibility either qualitatively argued away as a non-contributor or implemented in the logic model. This has not been done. Unlike the non-transient initiators, the format of the discussion for the transient initiators is that a single detailed discussion is provided for a general progression. This is followed by brief discussions of some of the other initiating event groups, but not in sufficient detail such that the progression can be clearly understood. The MSLB discussion touches on the qualitative basis for not addressing failure to isolate the MSLB, but there is insufficient justification and it does not affect the actual impact of single and multiple SG blowdown (for	The transient initiating event group discussion in R&R-PN-013 [CPNPP Accident Sequence Success] has been divided into sub-groups based on EOP progression. Each sub-group section discusses specific progression, timing, system states, procedures used, and operator actions. The sub-sections have been formatted similar to the other initiating events and include an ERG Actions portion that is specific to the sub-group. Model logic has been re-verified to confirm that no possible sequences have been excluded. Additional analysis has verified that failure to isolate single or multiple steamlines following a MSLB will not uncover the core, thus not requiring success criteria different from the overall transient group.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		example, is make-up required to compensate for primary shrinkage to prevent drawing a bubble into the RCS piping). This is finally followed by a single discussion of the ERG actions relevant to transients, but again this is only general in nature and does not present specific information on the different actions and procedures that are used for the various initiating event groups and how those could impact both plant and operator response (which would necessitate inclusion in the top logic). Assessment: AS-C2 was NOT MET; Assessment: AS-A10 was Cat I	Cat II or better based on this resolution
2-13	AS-A7 AS-C3	Key sources of model uncertainty and assumptions related to the accident sequence modeling are documented in R&R-PN-013 [CPNPP Accident Sequence Success], Section 3. There are some sources of uncertainty that are missing. For example: 1. The way offsite power recovery is handled in the accident sequences is not discussed as a potential source of uncertainty. The model assumes that, once offsite power is recovered the sequence is over. Therefore, the actual recovery and operation of the mitigating	1. Additional discussion of offsite power recovery modeling and sequence development added to PN-039 [CPNPP Quantification Support Files], App. E as follows: "A consideration of the off-site power recovery scheme is successful recovery and what happens once power is recovered. First, the methodology applies a non-recovery probability to the LOOP initiating event. That is, the cutset containing this initiating event has a probability associated with failure to recover power within a defined time frame. This failure leads to core damage. Second, if power recovery is successful, the additional failures required to lead to core damage produce cutsets that are non-minimal to the cutset with failed power recovery or another cutset, which would

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		systems after power recovery may introduce unique failures that are not addressed in LOOP sequences without SBO. In particular, after recovery of offsite power many things have to be done manually that would occur automatically for LOOP without SBO, and some equipment will be in a different state (i.e., handswitches in pull-to-lock). 2. While WCAP-15831 may be considered a "consensus" ATWS model, the WCAP includes consideration of ATWS from power levels less than 40% (States 1 and 2) that are not addressed in the CPNPP model. While these may be lesser contributors to the ATWS risk (~10%), the omission of parts of the "consensus" model does constitute a potential source of uncertainty that needs to be addressed. In addition, WCAP-15831 Section 8.2 states that "ATWS events can be initiated from a wide range of initiating events. The ATWS analysis for Westinghouse PWRs established that the limiting events, with regard to RCS peak pressure, are the loss of load with subsequent loss of all MFW and complete loss of normal feedwater. These limiting events are both assumed to be initiated from	thus be subsumed from the cutset file. The logic allows for the LOOP initiator to propagate through the model with the on-site AC power available. This generates cutsets that consider many of the additional failures associated with restarting and loading equipment or additional manual actions that may be required. For example, the following two cutsets are generated by the current methodology. Cutset one: LOOP IE, CCF of both EDGs, non-recovery probability Cutset two: LOOP IE, TDAFW FTS, CCF of MDAFW, CCP A FTS, PORV B FTO With no AFW and 1 PORV failed to open, success criteria will require 2 CCPs If off-site power was successfully recovered in cutset number one and the scenario continued, the cutset would look like: Cutset three: LOOP IE, CCF of both EDGs, power recovered, TDAFW FTS, CCF of MDAFW, CCP A FTS, PORV B FTO The quantification software would look at cutset three and cutset two and identify that cutset three was non-minimal to cutset two and remove it before the results would be written to the cutset file. Thirdly, if the model logic was modified to account for the successful restoration of off-site power, cutsets may be generated that contain unique failures after recovery that does not apply before recovery. That is, that after recovery of

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		normal operation at full power." It is further stated in Section 8.2.1 that "The model presented in this section assumes MFW is lost for all anticipated transient events. If MFW continues to operate, then the event does not need to address the pressure relief response, including AFW and AMSAC, but only requires long-term shutdown. A split that accounts for MFW continuing to operate may be added to plant specific ATWS model if desired." it is not clear that the modeling for the LOMFW top event captures all potential losses of MFW following the initiating event. For example, flood events INIT-F0-AUXSWA and INIT-F0-AUXSWB, as analyzed, would trip the CW pumps due to actuation of the flood sensing switches in the condenser pits resulting in a loss of condenser coincident with the reactor trip. However, these are treated as transients with MFW available in the ATWS analysis. In addition, random failure of MFW following reactor trip is not addressed in the fault tree logic for top event LOMFW (this was included in the Braidwood model described in Section 9.1 of the WCAP). Therefore, it is not clear that the CPNPP	offsite power many actions may have to be done manually that would occur automatically for LOOP without SBO, and some equipment will be in a different state. For example, 1) Loop IE, CCF of Both EDGs, Operator fails to establish FW after recovery of power, 2) Loop IE, CCF of Both EDGs, CCF of normal power tie breakers to safety busses to close or 3) Loop IE, CCF of Both EDGs, Operator fails to properly sequence loading of busses. For these remaining cases, the impact on CDF would be insignificant. This can be seen by looking at the overall make-up of these non-generated cutsets. For CPNPP the LOOP initiating event frequency is approximately E-2, the CCF of the EDGs is approximately E-4, providing an E-6 starting point probability. A best estimate of successful LOOP recovery prior to core damage would lower these cutsets by at least an order of magnitude, resulting in an E-7 cutset probability. For non-operator failure based scenarios, because of redundancy and/or diversity of equipment/success paths, at least two additional failures would have to occur in order to cause core damage. This would provide at least an E-4 failure probability. For operator failure based scenarios, given that once off-site power is restored, the focus of the staff would be on re-energizing the safety busses, followed by restoration of mitigating equipment and systems. Therefore a failure probability of E-3 would be an appropriate value based on current similar HRA analyses. This would put the non-generated cutsets in the E-10 to E-11 range (or lower) for a given core damage scenario. Given the

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		modeling is entirely consistent with the "consensus" model and the potential uncertainty introduced by the deviations is not discussed.	current model CDF value (~3E-06) and the contribution of LOOP (~ 10 to 15 percent) to CDF, these scenarios would not significantly contribute to overall CDF." The above information has been added to the Quantification Support File notebook, R&R-PN-039 [CPNPP Quantification Support Files]. 2. The ATWS event tree has been revised to pass all anticipated transient events discussed in the WCAP (i.e. no loop, no ISI) through the LOMFW logic. The split accounting for MFW continuing to operate has been removed. Concerning LOOP, the WCAP further states (§5.4): "Since the impacts on CDF and RCS integrity from LOSP/AWTS events are very small, this event will not be important to the plant risk profile or to risk-informed decision process for assessing changes to a plant." Regarding states 1 and 5 (low power), WCAP §5.4 also states: "Since the CDF and the impact on CDF are dominated by ATWS state 3 / 4 this state is the most important one to consider in plant specific PRA model. The other modes of operation are small contributors to plant risk and will not be important to the plant specific risk profile or to the risk-informed decision process for assessing changes to a plant." The results of the WCAP show that states 1 and 5 contribute less than 2.5% to ATWS risk. Since ATWS risk at CPNPP is a 0.1% contributor, the potential contribution to overall CDF risk from ATWS states 1 and 5 is on the order of 0.0025%. The uncertainty due to exclusion of ATWS states 1 and 5 is therefore confirmed to

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: AS-A7 was NOT MET	be insignificant to plant specific risk profile or to the risk-informed decision process for assessing changes to the plant. The above information has been added to the Accident Sequence notebook, R&R-PN-013. Cat II or better based on this resolution
2-16	HR-C2 HR-D2 HR-E2 HR-F2 HR-G2	R&R-PN-020 [Human Reliability Analysis], Section 4.1.2 states that "In general, caution was exercised when considering both an error of omission (EOM) and an error of commission (EOC) for the same activity. For most component manipulations, these activities were judged to be mutually exclusive. For example in the case of a repositioning a valve following a test, an error of omission skips the reposition. This would be a reasonable error. An error or commission, however would be to reposition the valve, i.e. the desired outcome, and is not considered." This is insufficient basis for excluding EOC. EOC could include (for this example) "repositioning" the wrong valve (correct intent, wrong action). This same thought process was applied to the EOC for post-initiator actions and was also not adequately justified. Assessment: HR-C2 was NOT MET	All HFEs have been re-analyzed to include appropriate Errors of Commission. Cat II or better based on this resolution

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
2-18	HR-H3 QU-C1	The process followed for dependency analysis utilizes the HRA Calculator® to identify the combinations of HFEs that appear in cutsets. The process used a quantification run with a truncation level of 1E-14 to identify the HFE combinations to assessed, but used nominal HEP values so it cannot be assured that all important combinations were identified. Assessment: QU-C1 was NOT MET	The cut set used in the re-analysis of dependency was generated by setting all HEPs to 1E-01 and re-quantifying at 1E-12, (which meets the ASME PRA Standard for setting a truncation value). Additional combinations were obtained and appropriately analyzed for dependency. 1E-01 is generally at least two orders of magnitude higher than the HEP values and is sufficiently elevated to identify important combinations. Cat II or better based on this resolution
3-1	IE-C5 IE-D2	From a methodology point of view, and per report R&R-PN-008A, Rev 4, with the exception of the LOOP initiators, a reactor year basis and an appropriate availability factor was used. So, it is deemed that the analysis meets the CC-I/II as a whole. However, because LOOP, as stated in section 4.7 of R&R-PN-008A [CPNPP Internal Initiating Events Data Analysis], Rev 4, uses a calendar year basis instead of a reactor year, an F&O was generated to document the need to convert the LOOP initiating events to reactor year based frequencies. Assessment: IE-C5 was Cat I/II	LOOP IE frequencies were adjusted to a reactor year basis and all other IE frequencies were re-verified to be calculated on a reactor year basis and documented in R&R-PN-008A. Cat II or better based on this resolution

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
4-1	IE-A1 IE-A4 IE-A5 IE-A7 IE-B2 IE-C3 IE-C11 IE-D2	In general, the initiating event analysis seems to have identified a representative set of initiating events. However, the following areas were identified where the documentation was missing or deficient in the current revision: 1. Appendix D of R&R-PN-008A [CPNPP Internal Initiating Events Data Analysis] (Rev. 3A) documents a systematic evaluation of each system to identify potential system initiating events. R&R-PN-024[CPNPP Support System Initiating Event] contains the support system initiators that include SW, CCW, CH and switchyard. It seems the systematic evaluation was performed, but not documented in detail in Revision 4 of R&R-PN-003 [CPNPP Initiating Events Analysis] or R&R-PN-008A. (IE-A1, IE-A5, IE-B2) 2. Page 20 of R&R-PN-008A (Attachment 5) contains a summary of the plant-specific initiating event experience. However, the treatment of events resulting in an unplanned controlled shutdown that includes a scram prior to reaching low-power conditions is not discussed. (IE-A7) 3. Section 8.0 of R&R-PN-003 [CPNPP Initiating Events Analysis] refers to a review of Licensee Event Reports (LERs), covering the period from September of 1988 through	1. The Initiating Event Analysis (PN-003) was revised to document the system-by-system initiating event review used to identify potential system initiating events. In addition, PN-003 was also upgraded to incorporate the documentation of the IE-D2 supporting requirement elements. 2. Added following text to PN-008A, §4.0: "A review of recent (see §4.2) plant operating experience was performed to identify occurrences of initiating events since the previous update. The only screening criterion used in this review was that a plant trip would not be counted if it was a planned event as part of a planned shutdown for refueling. In addition to at-power events, the review also looked for shutdown events that could also occur at power and events occurring during an unplanned controlled shutdown that resulted in a trip prior to reaching low power conditions." 3. NUREG/CR-6928 provides a reasonable expectation of common initiators for PWRs. A few of these initiators are not applicable to CPNPP. Similarly, CPNPP has a small number of "unique" initiators that have been added due to analysis or plant experience. Attachment 1 of PN-008A contains the mapping between IE's from industry sources and the CPNPP PRA model. PN-008A, §4.0 has the following summary: "Development of the initial CPNPP PRA model included a comprehensive search for initiating events and was documented in R&R-PN-003. Additionally, 2411 NRC LERs from September 1988 to May 1998 were re-reviewed during the revision to PN-003. All events could

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		May of 1998, to identify any industry initiating events which could not be placed in one of the identified Initiating Event categories. There is no documentation in the notebook providing details of this review such that it can be independently verified or reconsidered during future model updates. (IE-A4) 4. Recovery through cross-tie of the Unit 1 and Unit 2 SW and CCW systems (SWXTIE and CCWXTIE respectively) is credited in the Support System Initiating Event Fault Trees. However, this is not documented in R&R-PN-003 or R&R-PN-024. (IE-C3, IE-C11)	be placed within one of the existing initiating event categories. This search process is not repeated for PRA updates since the general set of PWR initiators is well established. A general search of recent industry events (INPO Operational Transients database and Ref. 2.7) did not identify any previously unseen types of initiating events. Review of references 2.1, 2.17, 2.18, 2.19 did not identify any initiators that are not included in the model, or any precursors that would indicate potential initiators were overlooked. Existing initiating event groups are consistent with other United States PWRs and do not require modification for this update. The initiator list bounds plant experience. The model freeze date for this update is 6/30/08. Attachment 1 is a summary of the updated internal initiating event frequencies. The calculations shown in Attachments 3-7 are documented in Excel spreadsheet "Rev4_Initiating_Events.xls". Calculations are performed as instructed in Ref. 2.5. A review of recent (see §4.2) plant operating experience was performed to identify occurrences of initiating events since the previous update. The only screening criterion used in this review was that a plant trip would not be counted if it was a planned event as part of a planned shutdown for refueling. In addition to at-power events, the review also looked for shutdown events that could also occur at power and events occurring during an unplanned controlled shutdown that resulted in a trip prior to reaching low power conditions. This review identified 7 plant trips during the period under

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: IE-D2 was NOT MET	consideration. These trips are listed in Attachment 5. No events were screened out during this review, nor were any initiating events identified that are not included in the current model. The system engineers were also interviewed to determine if the system model were missing any potential indicators. None were identified. The interviews are documented in ref. 2.42." Similarly, Operations reviewed the initiating event list during the updated operator interview. No changes were identified. 4. All SW and CCW crosstie recovery credit has been removed from the Support System Initiating Event fault trees. Cat II or better based on this resolution
4-4 Suggestion	IE-A8 IE-D2	The following reviews for identification of potential initiating events Interviews with plant personnel were not performed to determine if potential initiators have been overlooked. Assessment: IE-A8 was Cat I	Following text added to §4.0 of PN-008A: "The system engineers were interviewed to determine if the system model were missing any potential indicators. None were identified. The interviews are documented in R&R-PN-008A. Several Operations shift supervisors reviewed the list of current initiating events to determine if any potential initiating events had been overlooked. None were identified." Cat II or better based on this resolution

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
4-12	DA-D4 DA-E2	Section 4.3 of R&R-PN-008 [CPNPP Plant Specific Data Analysis] states that the resulting posterior distributions were reviewed and "any inconsistencies examined by comparing them to prior and plant experience. Results were determined to be reasonable based on the weight of evidence." However, there is no documentation associated with this review. Assessment: Cat I - III MET	Review results from the comparison of the ratio derived from plant specific data with prior mean values has been added to R&R-PN-008. Cat I - III MET
4-13	SY-B1 DA-D6	Section 4.5 of R&R-PN-008 states that a review of industry data sources and relative risk importance for SYSIMP groups supported deletion of eight common cause groups. The deleted CCF "component types" were fans, dampers, air compressors, bistables and non-safety batteries. Assessment: Cat II or better MET	The statement on review of common cause groups was incorrectly interpreted to indicate screening or exclusion. This statement in R&R-PN-008 has been clarified as follows: "To support the definition of common cause groups, component types were reviewed against industry data sources and relative risk importance for SYSIMP groups. No CCF events associated with significant basic events were excluded in the definition of common cause groups." Cat II or better MET
4-14	DA-D3 DA-E2	The CPNPP PRA includes mean values and statistical representations of the uncertainty intervals for the parameter estimates. However, the uncertainty parameters for the CCF events are not included.	The Multiple Greek Letter method for estimating CCF mean values is a method adopted from NUREG 5485 which is cited as a source in the ASME standard. Though this method does not readily support statistical representation of uncertainty intervals, other sources of uncertainty have been

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
			considered. As noted in Appendix D.5 of NUREG 5485, "the uncertainties due to judgment required in interpretation and classification of failure events and the assessment of impact vectors are the most significant of all sources of uncertainty." This discussion of uncertainty for CCF parameter estimation has been added to R&R-PN-008. The data notebook includes an explicit reference to R&R-PN-041, Uncertainty Analysis, which addresses EPRI recommendations for treatment of uncertainty. Cat III MET
		Assessment: Cat III MET	
4-15	DA-C4 DA-D1	The CPNPP PRA includes many SSCs with plant-specific parameter estimates (see Attachment 3 of R&R-PN-008). However, there is no documented systematic process or criteria to determine which SSCs should be evaluated for the plant-specific estimates, including the potentially significant basic events. Assessment: Cat II or better MET	A systematic review of plant specific data identified those components with sufficient, relevant plant data. All components with sufficient data were updated to generate plant specific parameter estimates. Data sources reviewed for changes in failures or failure modes included Maintenance Rule, Mitigation System Performance Indicator (MSPI), EPIX and consultations with System and Component Engineers. This discussion of the update process and criteria was added to R&R-PN-008. Cat II or better MET

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
4-24	IE-B5 IE-C3 IE-C11 QU-D1	Sections 5.2.1, 5.2.2, 5.2.3, 5.2.4 of R&R-PN-022 discuss the cutset reviews performed for CPNPP PRA. Issues were identified with two specific cutsets that require additional discussion and/or justification: 1. Cutset #9 in the CDF results contains two events (RHACHCOOL & RHBCHCOOL) which represent the conditional probability a RH train will fail upon loss of the essential chilled water that provide the room cooling. Each event has the conditional probability of 0.688 based on the RXE-SY-CP1/1-028 (1992). It is not clear whether this conditional probability is justifiable. In addition, it seems the RHACHCOOL & RHBCHCOOL events should be based on a joint probability when these two events show together in a cutset. (QU-D1) 2. Cutset #10 contains SWXTIE that credits Unit 2 SW system upon Loss of SW system in Unit 1 followed by an induced RCP Seal LOCA which would result in a start signal for the EDGs. It is not clear whether the operators have enough time to make the crosstie in time to provide the cooling to EDGs on Unit 1 before the diesels fail. (IE-B5, IE-C3, IE-C11, QU-D1)	1. The treatment of room cooling was reviewed and determined to be correctly applied, i.e. individual room heat loads are different, and thus different probabilities are reasonable. However, due to the uncertainty regarding potential dependency, cutsets containing failures of both trains are treated as completely dependent. A replacement event equal to the highest probability of the pair is substituted in place of the independent events. A sensitivity case [R&R-PN-041] has been performed to address the uncertainty of this assumption. Further discussion of this topic is addressed in App. D of R&R-PN-039. 2. All SW and CCW crosstie recovery credit has been removed from the Support System Initiating Event fault trees. PN-024 discusses credit for cross-ties to mitigate core damage but not in determining the SSIE frequencies. This crosstie function is credited as a recovery only with both trains in the other unit available. As modeled, one train from the other unit cannot be used to supply both units. Use of the crosstie does not prevent inducing an RCP Seal LOCA; nor does it prevent operators from taking required actions (e.g. stopping the EDGs on a loss of SW) prior to alignment of the crosstie.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: QU-D1 was NOT MET	Cat II or better based on this resolution
4-29 Suggestion	QU-A2 QU-D6 QU-F3	Section 6.0 of R&R-PN-022 provides the discussions of the significant contributors to CDF, the initiator contributions, and top event contributors for each event tree. Section 7.0 of R&R-PN-022 [CPNPP Accident Sequence Quantification] provides significant contributors from CCF events, operator actions and independent events. However, the sequence level contributors are not indentified in the notebook. Assessment: QU-F3 was Cat I	Discussion of significant sequences has been added to PN-022. Cat II based on this resolution
4-31	QU-E4 QU-F4	R&R-PN-041 provides the results of uncertainty and sensitivity results, and other PRA notebooks identify the potential sources of model uncertainty. However, it is not clear how these sources of uncertainty affect the PRA model. Assessment: QU-F4 was NOT MET	R&R-PN-041 Section 5.1 describes the application of the EPRI approach to CPNPP. Cat II based on this resolution
4-34	QU-F6	No documentation was found in R&R-PN-022, 39 and 41 providing a quantitative definition of significant basic event, cutset, and accident sequence.	The quantitative definition for significant basic event, significant cutset, and significant accident sequence is as described in ASME/ANS PRA Standard, part 2. This definition has been explicitly added to PN-022, 039, and 041.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: QU-F6 was NOT MET	Cat II based on this resolution
4-35	IE-C8 IE-C10 DA-C16	The CCW, SW, and CH initiating event fault trees use a MTTR factor, which is calculated based on the data from the Maintenance Rule database. It is not clear whether the data screening was appropriately handled for the initiating event criteria. In addition, the MTTR factor is applied using rules based recovery rather than being explicitly modeled in the SSIE fault trees as required by this SR.	The data used to calculate the MTTR value were screened to identify unavailability events not associated with planned test and maintenance. Detailed data includes dates, durations and the reason for unavailability. A table detailing screen results was added to R&R PN-008. MTTR events are explicitly included in SSIE model. The following is included in PN-024, §4.1: "Each SSIE tree has been developed such that every train is modeled with the operating equipment relying on an annualized exposure time. At an appropriate location, where the trains meet in the logic, an event representing the mean time to repair of the redundant train was placed. This event effectively replaces the annualized value of the redundant equipment with the MTTR exposure time. In this way, the logic will always result in a yearly frequency at the top while any of the operating trains may represent the initial annualized failure. An example of this approach is shown below, and each MTTR event used in the model is subsequently discussed. Standby equipment with relevant failure modes and common-cause failure events are modeled with an MTTR of 24 hours so that the mitigating logic may be used directly in most cases (see Section 3.2). These events, therefore, are modeled such that they bypass the additional MTTR events. (Common-cause failures are discussed in Section 6.0.) Other dual-train failure modes (such as shared tank ruptures) receive the yearly exposure which propagates to the top without further manipulation.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: IE-C10 was NOT MET	Cat II based on this resolution
6-4	IFSN-A6	RG 1.200 Revision 2 (Reference 8.5) documents a qualified acceptance of this SR. The NRC resolution states that to meet Capability Category II, the impacts of flood-induced mechanisms that are not formally addressed (e.g., using the mechanisms listed under Capability Category III of this requirement) must be qualitatively assessed using conservative assumptions. Assessment: IFSN-A6 was Cat I based on the qualification in RG 1.200, Revision 2	As noted, the qualitative analysis of impingement, pipe whip, humidity, and condensation concerns was not conducted for the PRA flood model; CPNPP previously completed a design basis High Energy Line Break (HELB) calculation. Since most of the high energy systems are located in compartments that are segregated from the rest of the plant by watertight doors and have flood paths directly to the plant yard there should be minimal impact to PRA equipment. Assessment: remains at Cat I Plant walkdowns confirmed that no high energy systems were located near the XST2 startup transformer, transformer cabling, or in the 6.9kV safety switchgear rooms. Therefore remaining in Cat I has no impact on this risk analysis.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
6-7	IFQU-A6	The human actions taken from the main control room during flooding scenarios (listed in Table 4.9-1 of R&R-PN-021 CPNPP Internal Flooding) were judged to not incur additional stress above the same actions when analyzed for the internal events analysis. This judgment is based on: (1) the components and cues not being affected by the flood, (2) the actions being based on steps as defined in a procedure, (3) the operators being highly trained in executing the procedure steps (many are memorized as immediate actions), and (4) the actions being backed up by supervision in the control room during the flooding scenario. Additionally, most of the actions are assumed to be taken early in a sequence before the determination that a flood is occurring (an average time frame of 10 minutes is assumed). Thus, few of the actions are expected to be taken in the long term as a scenario progresses. Certainly, the components in the control room (those physically manipulated by the operators) should not be affected by the flood scenarios. The lack of impact on cues is not certain. All the actions appear to be based on procedural guidance for which the operators are trained. Control room supervision is expected. However, the assumption regarding the actions	The nineteen HFE's that appear in flood cutsets were re-reviewed. Eleven of these HIs are performed in the control room and are simple actions (e.g. start an alternate pump, stop a pump, etc) in response to an alarm or EOP. The judgment is that these actions are not impacted by flood scenarios because they are simple, occur shortly after the trip, and are within the EOP. We strongly believe that the Operators will stay within the ERG network, as trained, until they have stabilized the plant. Further these events occur early enough that stress levels are judged to be unchanged from the level originally assessed for the event. WOG ERGs are symptom based. That is, the operators respond to plant indications rather than performing diagnosis of the event. No specific time limit is applied to this review. One HFE concerns equipment failed due to flooding. The HFE is therefore N/A. The remaining 7 actions have some portion of the response performed remotely (i.e. in the field). The general process was to increase transit time where the flood could cause the PEO to stop and have additional discussion with the control room and/or re-route to the destination. In lieu of more specific information, the transit time was doubled. Changing timing in the HRA methodology may change the dependency of recovery actions, with potential subsequent increase in the Human Error Probability (HEP). This approach was judged reasonable since the actions that were modified already include the effects of high stress in the base analysis. Three of the seven are not impacted by flood scenarios.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		being taken early within a scenario does not apply to several of the main control room actions that are listed in Table 4.9-1. At least nine actions from Table 4.9-1 were identified which could reasonably be expected to be performed in a time frame beyond the assumed, average 10 minutes. Among these actions were: - The failure to establish feed-and-bleed within 25 (or 30) minutes - The failure to align for low pressure recirculation (up to 41.8 minutes) - The failure to align for hot leg recirculation (up to 270 minutes) - The failure to start a standby SW pump (up to 37 minutes) - The failure to depressurize and begin RHR SDC (up to 1433 minutes) Assessment: Cat I - III MET	TLXHICSTFILY and AFXHICSTFILY are "refill the CST" actions and do not occur for at least 5.5 hours after plant trip. In this case the flood impacts are assumed to be terminated. EPXHICHASW_Y does not occur in a flood area. Four of the seven remote actions were judged to be potentially impacted by the flood. The potential impact was judged to likely be an increase in transit time due to additional communication with the control room or the need to take an alternate path. For these cases, transit time was doubled. Where appropriate, dependency levels were changed as a result of increased timing. In two of the four events the dependency level did not change, thus the HEP did not change. In the remaining two events, the dependency level increased, thus increasing the associated HEP. Cat I - III MET
No F&O included	IFEV-A6	R&R-PN-021 Section 4.7 indicates that the flood initiating event frequencies were based on the EPRI 1021086 failure data combined with plant-specific piping lengths. No Bayesian updating with plant-specific operating experience or adjustment based on engineering judgment was performed.	During the internal flooding (IF) analysis a search for previous IF events at CPNPP was performed and none were found. A Bayesian update with no specific plant events would incur a non-conservative result; therefore no Bayesian update was performed as there is no impact to application evaluations.

Table 1: F&O Summary of Findings			
F&O Number	**Associated Supporting Requirement**	**F&O Details**	**Resolution**
		Assessment: Cat I is MET	Assessment: remains at Cat I Remaining in Category 1 does not impact this analysis.
No F&O included	LE-C11	No credit was taken for continued operation of equipment after containment failure. RXE-LA-CPX/0-105 Table 6-1 specifically notes that "No credit is taken for operation of the ECCS/CS system after containment failure or for operator actions or other equipment that could be impacted by containment failure because there are none that are significant." It is not clear that this is equivalent to justifying "any credit given" as required for CC II/III. Assessment: Cat I is MET	Since no credit has been taken for continued operation after containment failure, justification cannot be provided. Remaining in Category 1 does not impact this analysis. Assessment: remains at Cat I
2-7 (Suggestion F&O)	SC-A6	The MAAP calculations (RXE-LA-CPX/0-103 and RXE-LA-CPX/0-104) are generally consistent with features and procedures. However, the requirement for switchover to hot leg recirculation is conservative, and may impact the CDF results and, thus, the insights on dominant contributors.	To address the conservatism, Hot Leg Recirculation requirements were removed for Small and Very Small LOCA based on Westinghouse ERG documents and comparison with other plants. Assessment: remains at Cat I-III

APPENDIX B to TXX-12084

COMPARISON OF IPEEE FIRE ANALYSIS TO RG 1.200 SECTION 1.2.4

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Plant Boundary Definition and Partitioning	Global analysis boundary captures all plant locations relevant to the fire Probability Risk Assessment (PRA).	Fire areas and zones were defined in accordance with Electric Power Research Institute (EPRI) Report, "Fire Risk Analysis Implementation Guide," Project 3385-01 (Draft), January 1994 and determined (partitioned) as detailed in the Comanche Peak Nuclear Power Plant (CPNPP) Fire Hazards Analysis (February 15, 1991). Minimum Fire Rating for barriers was 1 hour.	Walkdown for startup transformers (STs) XST1 and XST2 cabling was conducted to confirm boundaries. No changes were noted and Individual Plant Examination of External Events (IPEEE) information was used.
	Physical analysis units are identified by credited partitioning elements that are capable of substantially confining fire damage behaviors.	Fire areas/compartments were explicitly defined. Analysis included development of detailed barrier information, determination of spreading across barriers, and effectiveness of suppression systems. An explicit multi-compartment review was conducted.	

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Equipment Selection	Equipment is selected for inclusion in the plant response model that will lead to a fire-induced plant initiator, or that is needed to respond to such an initiator (including equipment subject to fire-induced spurious actuation that affects the plant response).	The original IPEEE fire analysis reviewed all components in the individual plant examinations (IPE) model in addition to non-IPE components for fire induced plant initiators and response to the initiators (mitigation). This review was performed by analyzing each of the fire zones for the components in the room and the resulting impact to the PRA model (e.g., reactor trip, loss of supporting systems, no impact to plant operation, etc.). The IPEEE fire modeling did not address the impact of fire induced spurious operations.	The analysis used the current PRA model (Revision 4A) which contained the majority of the components that existed in the IPEEE analysis. Components that are no longer in the PRA model that were impacted by the fire analysis were incorporated via a surrogate component or model change, as necessary. Fire induced spurious operations were incorporated for the fire scenarios that were assessed in this license amendment request (LAR).
	The number of spurious actuations to be addressed increases according to the significance of the consequence (e.g., interfacing systems loss of coolant accident (LOCA).	The IPEEE analysis used the CPNPP internal events IPE model which included modeling of spurious operations of certain types of equipment (transfer open, transfer closed, etc.) which were assumed to occur if a component were damaged by the fire. However, no formal assessment of fire induced spurious operations was performed	See the fire analysis discussion of this document for further details. Multiple spurious actuations were considered for the fire scenarios that were reassessed and were not limited.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Equipment Selection (Continued)	Instrumentation and support equipment are included.	Instrumentation and supporting equipment that are required for automatic actuations and the engineered safety features actuation system (ESFAS)/reactor protective system (RPS) systems were model in the IPEEE. However, instrumentation and supports used for the purpose of diagnosing plant conditions were not incorporated.	IPEEE Methodology was used.
Cable Selection	Cables that are required to support the operation of fire PRA equipment (defined in the equipment selection element) are identified and located.	Equipment and cable location data were developed based on the CPNPP Master Equipment List (MEL) and INDMS (Integrated Nuclear Data Management System Cable database) information for all IPE components. The cable database included ALL cable raceways that were impacted by each of the fire scenarios whether or not they included IPE equipment.	IPEEE cable selection was used.
Qualitative Screening	Screened out physical analysis units represent negligible contributions to risk and are considered no further.	Fire areas/zones screened out when they did not result in an automatic, manual, or controlled shutdown -AND- did not affect IPE-related equipment. However, these fire areas/fire zones were included in the multi-compartment analysis.	IPEEE qualitative screening analysis was not modified.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Fire PRA Plant Response Model	Based upon the internal events PRA, the logic model is adjusted to add new fire-induced initiating events and modified or new accident sequences, operator actions, and accident progressions (in particular those from spurious actuations).	Fire induced spurious operation were not explicitly evaluated in the IPEEE. The fire analysis was performed using the IPE model incorporating model modifications to accident sequences, operator actions, and accident progressions as necessary for each fire scenario.	The current revision of the PRA model fault tree was modified to incorporate the impacts of fire induced spurious operations for the identified scenarios. Additionally the model was modified to incorporate changes to accident sequences and progressions as necessary (through the use of flag files and fault tree changes). No operator actions modifications were made.
	Inapplicable aspects of the internal events PRA model are bypassed.	Portions of the IPE model not applicable in the fire IPEEE were bypassed (e.g. mechanistic LOCAs, etc.)	IPEEE methodology was used.
Fire Scenario Selection and Analysis	Fire scenarios are defined in terms of ignition sources, fire growth and propagation, fire detection, fire suppression, and cables and equipment ("targets") damaged by fire.	Scenarios developed using five primary steps: 1) fire ignition source and frequency, 2) fire area/zone screening, 3) fire propagation and damage evaluation, 4) detailed fire modeling, and 5) evaluation of detection and suppression.	IPEEE methodology was used.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Fire Scenario Selection and Analysis (Continued)	The effectiveness of various fire protection features and systems is assessed (e.g., fixed suppression systems).	Detection and suppression evaluated based on fire source, detector type and location, and other zone features. Separation criteria of 10CFR50 App R III.G.2 was applied related to hot gas layer (HGL) scenarios (full area suppression). Partial coverage analysis was conducted per CPSES Calc 0210-063-0064,"Partial Sprinkler Coverage Evaluation."	For the scenarios that were identified it was assumed equipment in the room were failed immediately as a result of the fire; no credit for suppression was taken to prevent equipment damage. This was consistent with the IPEEE methodology for these fire scenarios.
	Appropriate fire modeling tools are applied.	IPEEE methodology applied - walkdown workbooks for fixed/transient ignition sources, evaluation calculations for fire propagation and damage assessment, and as needed HGL calculations. The plume analysis and fire damage calculations were performed using fire propagation spreadsheets with guidance from the "Fire Risk Analysis Implementation Guideline" (Project 3385-01) (Reference 8.14) and the "Fire-Induced Vulnerability Evaluation" (EPRI Project 30000-41) (Reference 8.48) documents.	IPEEE methodology was used.
	The technical basis is established for statistical and empirical models in the context of the fire scenarios (e.g., fire brigade response).	For all detailed fire modeling, fire brigade organization and response analysis was evaluated.	IPEEE methodology was used, but did not apply to the identified scenarios.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Fire Scenario Selection and Analysis (Continued)	Scenarios involving the fire-induced failure of structural steel are identified and assessed (at least qualitatively).	Not included in the IPEEE.	Not included.
Fire Ignition Frequencies	Frequencies are established for ignition sources and consequently for physical analysis units.	The EPRI "Fire Events Database for Nuclear Power Plants" (NSAC-178L) (Reference 8.49)was used to determine the ignition frequencies employing the methodology defined in the EPRI "Fire Risk Implementation Guideline" (Project 3385-01) and EPRI "Fire-Induced Vulnerability Evaluation (FIVE)" (EPRI Project 30000-41) (Reference 8.48).	IPEEE frequencies used.
	Transient fires should be postulated for all physical analysis units regardless of administrative controls.	Administrative controls were used to limit the location of transient combustible analysis.	IPEEE methodology used.
	Appropriate justification must be provided to use nonnuclear experience to determine fire ignition frequency.	Not applicable - no non-nuclear frequencies were used.	Not applicable; IPEEE Methodology used.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and -Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Quantitative Screening	Physical analysis units that are screened out from more refined quantitative analysis are retained to establish CDF and LERF/Large Release Frequency (LRF).	The fire zones determined to be screened from the further analysis were kept within the documentation but the values were not added to the to the cumulative fire calculation.	IPEEE Methodology was used.
	Typically, those fire PRA contributions to CDF and LERF/LRF that are established in the quantitative screening phase are conservatively characterized.	Screening based on standards in the Fire Risk Implementation guide and FIVE methodology were used and assumed to be conservative.	IPEEE Methodology was used.
Circuit Failure Analysis	The conditional probability of occurrence of various circuit failure modes given cable damage from a fire is based upon cable and circuit features.	Fire induced spurious operations were not modeled and no circuit analysis was performed.	No circuit analysis was performed for this LAR. A large probability was used for each of the model fire induced spurious operations (5E-01) for those scenarios that explicitly modeled them; see fire analysis section of this document for further details.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Post-fire Human Reliability Analysis	Operator actions and related post-initiator human factor engineering (HFEs) conducted both within and outside of the main control room, are addressed.	Operator actions both within and outside of the control room were reassessed using the methodology contained in EPRI Technical Report "SHARP1-A Revised Systematic Human Action Reliability Procedure" (EPRI Project 3206-01) (Reference 8.50).	The operator actions for the internal events model were not modified for this risk assessment; the model of record values were retained. The operator action frequencies were not modified based on the intent of the risk assessment for this fire analysis being to determine the risk insights for removing the ST XST1 for an extended duration (e.g., two, one-time 14-day CTs). Therefore quantitative cutset results for the baseline and XST1 ST out-of-service scenarios were compared and reviewed for operator actions that appeared in the resulting DELTA cutsets. These DELTA cutsets were then used to reveal the operator actions that could potentially be more important given that the ST XST1 out-of-service. The result of this review did not reveal any operator actions that became more dominant in the ST XST1 out-of-service case.
	The effects of fire-specific procedures are identified and incorporated into the plant response model.	Operator actions from fire procedures that were determined to be required in the IPEEE model were incorporated.	
	Plausible and feasible recovery actions, assessed for the effects of fire, are identified and quantified.	IPEEE recovery actions were limited to those that were procedurally governed and determined to feasible to the fire scenario based on the SHARP methodology.	
	Undesired operator actions resulting from spurious indications are addressed.	Not included.	Not included.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Post-fire Human Reliability Analysis (Continued)	Operator actions from the internal events PRA that are retained in the fire PRA are assessed for fire effects.	Many of the operator actions were reassessed for their impacts on fire response. However, some operator actions within the IPEEE model were screened from being reassessed based on the fire's impact to accident progression and conservatisms in the assumptions. The operator actions that were screened from reassessment retained their IPE values.	All operator action values in the PRA model were unchanged, see previous discussion.
Fire Risk Quantification	For each fire scenario, the fire risk results are quantified by combining the fire ignition frequency, the probability of fire damage and the conditional core damage probability (and CLRP/CLERP) from the fire PRA plant response model.	The IPEEE analysis quantification used the ignition frequency, the probability of fire damage (non-suppression), and the conditional core damage probabilities from the IPE model.	IPEEE Methodology was used.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Fire Risk Quantification (Continued)	Total fire-induced Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)/LRF are calculated for the plant and significant contributors identified.	Total fire induced CDF was calculated in the IPEEE, but LERF/LRF were not calculated.	Total CDF and LERF were not calculated as the analysis performed was only for the fire scenarios determined to significantly impact the ST XST1 out-of-service cases. However, the CDF and LERF values along with ΔCDF, ΔLERF, Incremental Conditional Core Damage Probability (ICCDP), and Incremental Conditional Large Early Release Probability (ICLERP) values were all calculated.
	The contribution of quantitatively screened scenarios (from the quantitative screening element) is added to yield the total risk values.	This was not performed in the IPEEE.	This was not done for this analysis as only certain fire scenarios were reanalyzed.

Comparison of IPEEE Fire Analysis to RG 1.200 Section 1.2.4			
Element	**Technical Characteristics and Attributes**	**CPNPP IPEEE**	**XST1 LAR Analysis**
Seismic Fire Interactions	Potential interactions resulting from an earthquake and a resulting fire that might contribute to plant risk are reviewed qualitatively	A seismic/fire interaction study was performed and the seismic walkdowns identified any potential fire hazards. The results of the IPEEE seismic/fire interaction study concluded that "...there are no significant fire ignition hazards related to seismic/fire interactions."	No seismic/fire analysis was re-performed but the walkdowns conducted for this XST1 out-of-service LAR confirmed that the conclusions from the IPEEE analysis remain the same. Walkdowns determined there were no changes to the flammable liquids or flammable gas storage locations within the plant.
	Qualitative assessment verifies that such interactions have been considered and that steps are taken to ensure that the potential risk contributions are mitigated	The IPEEE took the potential seismic fire interactions into account and determined that adequate processes were in place to mitigate the potential risk contributions.	IPEEE methodology was used.
Uncertainty and Sensitivity	Uncertainty in quantitative fire PRA results because of parameter uncertainties is evaluated.	Not included.	Uncertainties were evaluated for the internal events and internal flooding model. No additional uncertainty analysis was performed for the fire scenarios.
	Model uncertainties as well as the potential sensitivities of the results to associated assumptions are identified and characterized.	Not included.	

ATTACHMENT 2 to TXX-12084

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

Page 3.8-2

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	
	A.2 ----------NOTE---------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ---------- 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 OR 14 days for ~~a~~ one-time outages on XST1~~2~~ two, to complete a plant modification to be completed by March 31, 201~~4~~5.

ATTACHMENT 3 to TXX-12084

PROPOSED TECHNICAL SPECIFICATIONS BASES CHANGES
(Markup For Information Only)

Pages B 3.8-8

BASES

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.

two

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.

two,

are

An OR statement for a temporary Completion Times is added to the Completion Time above (72 hours). The one-time, 14-day Completion Times is applicable to XST12 only and expires on March 31, 20141. The 14-day Completion Times apply~~ies when making the final terminations~~ as part of the plant modification to facilitate connection of either XST12 or XST1A ~~spare~~ startup transformers to the 1E buses. If during the conduct of the prescribed maintenance outage, should any combination of the remaining OPERABLE AC Sources be determined inoperable, current TS requirements would apply.

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 met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related 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. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

(continued)

ATTACHMENT 4 to TXX-12084

RETYPED TECHNICAL SPECIFICATION PAGES

Page 3.8-2

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	
	A.2 ----------NOTE---------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ---------- 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 OR 14 days for two one-time outages on XST1 to complete a plant modification to be completed by March 31, 2014.

ATTACHMENT 5 to TXX-12084

RETYPED TECHNICAL SPECIFICATION BASES PAGES

Pages B 3.8-8

BASES

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.

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.

An OR statement for two temporary Completion Times is added to the Completion Time above (72 hours). The two-time, 14-day Completion Times are applicable to XST1 only and expires on March 31, 2014. The two, 14-day Completion Times apply as part of the plant modification to facilitate connection of either XST1 or XST1A startup transformers to the 1E buses. If during the conduct of the prescribed maintenance outage, should any combination of the remaining OPERABLE AC Sources be determined inoperable, current TS requirements would apply.

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 met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related 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. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

(continued)

ATTACHMENT 6 to TXX-12084

PROPOSED FSAR CHANGES
(For Information Only)

Pages 8.2-1
8.2-2
9.5-17

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

TO's transmission system serves as the main outlet and source of offsite power for the CPNPP. Connection of the station outputs to the system is achieved via 345-kV overhead lines to the 345-kV switchyard. Separate connections to the 138-kV switchyard and the 345-kV switchyard provide independent and reliable offsite power sources to the Class 1E systems of each unit.

Because the 345-kV system forms the backbone of the TO transmission system, it provides a highly reliable source of continuous power for plant shutdown. Another reliable source is the 138-kV network.

The TDSP's high-voltage (HV) switchyards at CPNPP consist of 345-kV switching facilities and 138-kV switching facilities and are an integral part of the TO transmission system. The network interconnections to CPNPP switchyards are made through seven 345-kV and two 138-kV transmission lines to other switching stations within the TO transmission system as shown on Figure 8.2-4. There are no interconnections between the 138-kV switchyard and the 345-kV switchyard at the CPNPP site. The 138-kV switchyard is physically and electrically independent of the 345-kV switchyard.

Essentially, the 345-kV and the 138-kV switchyards each consist of a two-bus arrangement having one breaker per transmission circuit. Transmission circuits terminate in individual positions on alternate buses in the switchyards. Power can be supplied to each switchyard from any of their respective transmission circuits.

The CPNPP switchyards are located approximately 600 ft due west of the Turbine Building. Figure 8.2-1 shows the physical orientation and separation of the high-voltage switchyards, main, station service and startup transformers, and transmission lines routing from the transformers, and transmission lines routing from the transformers to the switchyards. The CPNPP HV switchyards' configurations are shown on Figure 8.2-4.

Two three-phase, half-size, step-up transformers are provided for each unit to raise the 22-kV generator voltage to 345-kV prior to transmission via overhead lines to the CPNPP 345-kV switchyard. Each CPNPP unit output line is connected to both 345-kV buses through two breakers which function as generator circuit breakers. The units are synchronized to the system across the generator circuit breakers. In the event of a unit trip, these breakers isolate the associated generator from the system. If required, the generators can be isolated individually by removing the bus links in the main isolated-phase bus, permitting energization of the non-safety-related 6900-V auxiliary bus system by closing the generator circuit breakers and backfeeding through the main and unit auxiliary transformers.

The CPNPP offsite power source line for start up transformer XST1 is connected to both 138-kV buses thru two breakers which function as a bus tie. The offsite power source line for start up transformer XST2 is connected to both 345-kV buses thru two breakers which function as a bus tie.

Startup transformer XST2, spare startup transformer XST2A and station service transformer 1ST are connected to a common overhead line from the 345-kV switchyard. Each transformer is

provided with a 345-kV motor-operated air switch such that each transformer can be energized independent of the other transformer.

~~Spare~~ startup transformer, XST2A with dual primary windings (345-kV and 138-kV), is in a dedicated location under the 345-kV line to XST2 (refer to Figure 8.2-1) to serve as a replacement of XST2. Cable buses from secondary X and Y windings of XST2 and XTS2A are connected to two 6.9kV transfer panels to provide 345kV offsite power to Units 1 and 2 safety related buses. These transfer panels allow transfer of 345kV offsite power source for safety related buses from XST2 to XST2A and vice verse. ~~This spare transformer may be physically relocated to a dedicated location near XST1, to serve as a replacement of XST1.~~

Station service transformer 2ST is connected to the 345-kV switchyard west bus via a dedicated circuit breaker and overhead line.

Alternate

The 138-kV and 345-kV circuit breakers are provided with an energy storage mechanism that allows the operation of the individual circuit breaker without having an external source of power. The circuit breakers have two separate avenues of relay protection termed primary and secondary or backup to provide a high degree of operational reliability.

The 125-VDC supply, for each of the switchyard relays, is segregated into two completely independent systems, one for the primary relays and the other for the backup relays. These two systems are independent of both the station DC systems and the DC systems of the other switchyard.

The 345-kV switchyard TO circuit breakers may be operated from either the 345-kV Switchyard Control Building or remotely from Oncor's System Operations Center. Control of CPNPP 345-kV switchyard circuit breakers and motor-operated air switches is administered from the plant Control Room except for the motor-operated air switch for transformer XST2A, which has local motor control. The 138-kV switchyard circuit breakers may be operated from either the 138-kV Switchyard Relay House or remotely from TO's System Operations Center. The 138-kV motor-operated air switch (DXST1) may be operated from the Control Room. The 125-VDC control power for circuit breakers and motor-operated air switches in the 345-kV system is independent of the 125-VDC control power for circuit breakers and motor-operated air switches in the 138-kV system.

Physical layouts of the switchyards are shown in Figures 8.2-5 and 8.2-7.

The substations that are connected to the CPNPP switchyards (as shown on Figure 8.2-4) are as follows:

- DeCordova (138-kV)
- Stephenville (138-kV)
- DeCordova (345-kV)
- Wolf Hollow (345-kV)
- Everman (345-kV)

Alternate startup transformer XST1A is in a dedicated location under the 138-kV line to XST1 (refer to Figure 8.2-1) to serve as a replacement of XST1. Cable buses from secondary X and Y windings of XST1 and XTS1A are connected to two 6.9kV transfer panels to provide 138kV offsite power to Units 1 and 2 safety related buses. These transfer panels allow transfer of 138kV offsite power source for safety related buses from XST1 to XST1A and vice versa.

electrical faulting. All cable trays, conduits, and their supports are constructed of noncombustible materials.

Outside the Containment buildings, where cable trays containing cabling related to both redundant trains of equipment required to bring the plant to a hot standby condition, and where both trains are located in the same fire area, and are not separated by a negligible combustible horizontal distance of greater than or equal to 20 feet, and are not comprised of one hour fire rated cable, one train of cabling will be protected by at least a one hour rated fire barrier. Where this situation exists, automatic sprinklers are arranged to provide coverage adequate for the hazards in the area. Sprinklers are also provided for cabling where there is a congestion of cable trays see Section 9.5.1.6.1d. Fire stops are provided within the cable trays whenever the cables penetrate walls or floors designated as fire barriers. Fire stops are not provided at intermediate points in vertical or horizontal cable runs, except in long vertical runs. In such instances, fire stops are located at intervals equivalent to floor spacings. It is a general installation practice that vertical tray runs are provided with solid, sheet steel covers for a minimum distance of 4 feet above the floor where necessary for physical protection of the cable. Fire stops are not provided in cable trays inside the Containment Buildings. Conduit fire stops are provided when the conduit penetrates a designated fire barrier and is not run continuously through the fire area (as described in Section 9.5.1.6.1.D.3.d).

9.5.1.5.6 Transformers

All interior transformers are of the air-cooled dry type and do not contain any insulating oil. The main, unit auxiliary, station service and startup transformers are oil-cooled and are located outdoors adjacent to the Turbine Buildings. The main transformers are separated from each other, as well as from the Turbine Buildings, by a blank three-hr rated fire wall. The unit auxiliary transformer and startup transformers XST1 and XST2 are separated from the Turbine Buildings by a three-hr rated fire wall. Penetrations in this wall within 50 ft from each side of the center line of the transformer are protected in order to maintain the fire-resistant integrity of the wall. Additional walls are provided extending out from the Turbine Building wall to protect the ventilation openings located in the exterior Turbine Building wall. Station service transformers 1ST and 2ST and spare transformer XST2A are separated from the Turbine Building by a distance greater than 50 feet.

Alternate transformer XST1A is separated from adjacent structures by a three-hour rated fire wall.

9.5.1.5.7 Flammable Liquid and Gas Storage

1. Flammable Liquid Storage

All significant amounts of flammable liquids are stored in separate fire areas that are isolated from the adjacent plant areas by three-hr fire rated barriers. As a minimum, fire detectors are provided in each area, and dependent upon the hazard, a fixed fire extinguishment system is provided. In all instances, such areas do not present a potential hazard for equipment located in the adjacent areas.

2. Flammable Gas Storage

Bulk storage of all flammable explosive gases is located outside the primary, secondary and turbine plant buildings. The storage facility is an open structure located outdoors in the yard adjacent to the security fence. An explosion or fire in this area will not affect any of the primary plant buildings.

ATTACHMENT 7 to TXX-12084

SUMMARY OF REGULATORY COMMITMENTS

Regulatory Commitment Summary

Number	Commitment	Due Date/Event
The Following Commitments Are Associated With The 138kV Work		
4441997	During a 14-day CT, the APDG provided for each Unit will be verified available to provide power to equipment for long term cooling once per shift.	During the 14-day CT for the 138kV work.
4456419	During a 14-day CT, if an APDG becomes unavailable, both Units shall enter Condition C of TS 3.8.1 and start shutting down within 24 hours. (This 24-hour period will only be allowed once within a 14-day CT.)	During the 14-day CT for the 138kV work.
4442002	Prior to initiation of a one time, 14-day CT extension, PM task for breakers 1EA1-1, 1EA2-1, 2EA1-1 and 2EA2-2 will be verified as current.	Prior to the start of the 14-day CT for the 138kV work.
4442007	Testing of EDGs, APDGs, and TDAFWPs will occur within the two (2) weeks prior to the start of the XST1 CT.	Within two weeks prior to the start of the 14-day CT for the 138kV work
4442008	The EDGs, APDGs, TDAFWPs, XST2, CCWPs, and SSWPs will have ALL testing and maintenance activities suspended for the duration of a one-time, 14-day CT for XST1. Additionally, signs will be placed on the doorways to the equipment, or in the case of XST2 around the equipment, noting the restriction of testing and maintenance during this XST1 CT.	During the 14-day CT for the 138kV work.
4442010	A roving hourly fire watch will be in effect during the 14-day XST1 CT along the path of the XST2 power and control cabling. This is an additional measure to monitor the area for fire risks that could damage and disable the XST2 transformer cabling.	During the 14-day CT for the 138kV work.
4442011	Local weather conditions and forecasts will be monitored by Operations twice per shift to assess potential impacts on plant conditions.	During the 14-day CT for the 138kV work.
4442013	Based upon the NOAA weather curves, a time in which severe weather is not expected will be selected for implementation of the XST1 CT. As shown in the weather curves, this time frame is September 1 through March 31. This planned timing will reduce the risk associated with high wind/tornados and weather challenges to the plant during the XST1 CT.	During the 14-day CT for the 138kV work.
4442016	The seismic walkdown will be completed prior to the XST1 CT to identify any issues that could impact the EDGs and TDAFWPs during a seismic event. These impacts include mounting or interactions issues including loose parts and missing hardware. This walkdown is for assurance that these components will meet their seismic design criteria in the event of a seismic incident.	Within two weeks prior to the start of the 14-day CT for the 138kV work
4442028	Access to both switchyards and relay houses will be controlled and posted, and all maintenance will be suspended for the duration of the CT on XST1.	Prior to the start of the 14-day CT for the138 kV work
4442046	CPNPP's Operations Department will contact the Transmission Operator (Transmission Grid Controller) once per day during a 14-day Completion Time to ensure no problems exist in the transmission lines feeding CPNPP or their associated switchyards that would cause post trip switchyard voltages to exceed the voltage required by STA-629.	During the 14-day CT for the 138kV work.

Number	Commitment	Due Date/Event
4442047	Just-in-time training for affected work groups will be completed prior to the start of a XST1 outage.	Prior to the start of the 14-day CT for the 138kV work
4442049	All hot work activities along the routing associated with power and control cabling for XST2, the in-service ST, will be suspended during the XST1 CT. This is to reduce the risks associated with fires that could damage and thus disable the XST2 transformer cabling.	During a 14-day CT for the 138kV work.
4456879	In the two weeks prior to the start of the CT, a thermographic survey will be conducted on the two fixed sources in the safeguards switchgear room to verify no abnormalities exist. This is to reduce the likelihood of a fire ignition.	Within two weeks prior to the start of the 14-day CT for the 138kV work
4457002	Both Unit 1 and 2 Transient Combustible safe zones identified in the fire analysis (TSN4-082) and the cable routing for the XST2 transformer will have additional restrictions relating to combustible storage during the extended CT durations. Implementing this risk reduction measure will reduce the fire risks that were identified for the transient combustible scenarios in the fire analysis.	During a 14-day CT for the 138kV work.
The Following Commitments Are Associated With The 6.9kV Work		
4457004	During a 14-day CT, the APDG provided for each Unit will be verified available to provide power to equipment for long term cooling once per shift.	During the 14-day CT for the 6.9kV work.
4457005	During a 14-day CT, if an APDG becomes unavailable, both Units shall enter Condition C of TS 3.8.1 and start shutting down within 24 hours. (This 24-hour period will only be allowed once within a 14-day CT.)	During the 14-day CT for the 6.9kV work.
4457007	Prior to initiation of the one time, two CT extensions, PM task for breakers 1EA1-1, 1EA2-1, 2EA1-1 and 2EA2-2 will be verified as current.	Prior to the start of the 14-day CT for the 6.9kV work.
4457008	Testing of EDGs, APDGs, and TDAFWPs will occur within the two (2) weeks prior to the start of the XST1 CT.	Within two weeks prior to the start of the 14-day CT for the 6.9kV work
4457016	The EDGs, APDGs, TDAFWPs, XST2, CCWPs, and SSWPs will have ALL testing and maintenance activities suspended for the duration of a one-time, 14-day CT for XST1. Additionally, signs will be placed on the doorways to the equipment, or in the case of XST2 around the equipment, noting the restriction of testing and maintenance during this XST1 CT.	During the 14-day CT for the 6.9kV work.
4457030	A roving hourly fire watch will be in effect during the 14-day XST1 CT along the path of the XST2 power and control cabling. This is an additional measure to monitor the area for fire risks that could damage and disable the XST2 transformer cabling.	During the 14-day CT for the 6.9kV work.

Number	Commitment	Due Date/Event
4457033	Local weather conditions and forecasts will be monitored by Operations twice per shift to assess potential impacts on plant conditions	During the 14-day CT for the 6.9kV work.
4457041	Based upon the NOAA weather curves, a time in which severe weather is not expected will be selected for implementation of the XST1 CT. As shown in the weather curves, this time frame is September 1 through March 31. This planned timing will reduce the risk associated with high wind/tornados and weather challenges to the plant during the XST1 CT.	During the 14-day CT for the 6.9kV work.
4457044	The seismic walkdown will be completed prior to the XST1 CT to identify any issues that could impact the EDGs and TDAFWPs during a seismic event. These impacts include mounting or interactions issues including loose parts and missing hardware. This walkdown is for assurance that these components will meet their seismic design criteria in the event of a seismic incident.	Within two weeks prior to the start of the 14-day CT for the 6.9kV work
4457119	Access to both switchyards and relay houses will be controlled and posted, and all maintenance will be suspended for the duration of the CT on XST1.	Prior to the start of the 14-day CT for the 6.9kV work
4457121	CPNPP's Operations Department will contact the Transmission Operator (Transmission Grid Controller) once per day during a 14-day Completion Time to ensure no problems exist in the transmission lines feeding CPNPP or their associated switchyards that would cause post trip switchyard voltages to exceed the voltage required by STA-629.	During the 14-day CT for the 6.9kV work.
4457122	Just-in-time training for affected work groups will be completed prior to the start of a XST1 outage.	Prior to the start of the 14-day CT for the 6.9kV work
4457123	All hot work activities along the routing associated with power and control cabling for XST2, the in-service startup transformer, will be suspended during the XST1 CT. This is to reduce the risks associated with fires that could damage and thus disable the XST2 transformer cabling.	During a 14-day CT for the 6.9kV work.
4457124	In the two weeks prior to the start of the CT, a thermographic survey will be conducted on the two fixed sources in the safeguards switchgear room to verify no abnormalities exist. This is to reduce the likelihood of a fire ignition.	Within two weeks prior to the start of the 14-day CT for the 6.9kV work
4457125	Both Unit 1 and 2 Transient Combustible safe zones identified in the fire analysis (TSN4-082) and the cable routing for the XST2 transformer will have additional restrictions relating to combustible storage during the extended CT durations. Implementing this risk reduction measure will reduce the fire risks that were identified for the transient combustible scenarios in the fire analysis.	During a 14-day CT for the 6.9kV work.