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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
10CFR50.59 EVALUATION SUMMARY REPORT 0011

Gentlemen:

Please find attached the report required by 10CFR50.59(b)(2) for those activities which were completed or partially completed at CPSES Units 1 and 2 between February 2, 2002, and August 2, 2003, and which were not reported to the NRC in a previous submittal. This report contains a brief description of the changes, tests and experiments implemented or performed pursuant to 10CFR50.59(a), including a summary of the evaluations for each. Items in this report are referenced by their 10CFR50.59 Evaluation Numbers. This report also includes certain activities completed or partially completed after August 2, 2003.

TXU Energy did not make commitment material changes which require reporting for CPSES Units 1 and 2 per the recommendations of NEI document, "Guideline for Managing NRC Commitments," Revision 2.

IE47

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

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Fred W. Madden
Nuclear Licensing Manager

JDS/js
Attachment

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

ATTACHMENT to TXX-04018

59EV-2000-002255-01-00
59EV-2001-001672-01-00
59EV-2002-000129-01-00
59EV-2002-001062-01-00
59EV-2002-002151-01-00
59EV-2002-002189-01-00
59EV-2003-001198-01-00

Evaluation Number: 59EV-2000-002255-01-00 **Units 1 and 2**
Revision 0

Activity Description:
Revise Plant Operations Procedure SOP 507 to allow one operating Reactor Makeup Water Pump to be shut down during normal plant operation for equipment rotation, etc. Update UFSAR Section 9.2.3.2 to reflect text changes from "As a minimum, one reactor makeup water pump per unit operates constantly." to "As a minimum, one reactor makeup water pump per unit is normally operating."

Both the common pump and the unit specific pump may be stopped during equipment rotation (i.e., transfer from the unitized pump to the common pump and vice versa which require valve position changes) to protect the diaphragm style isolation valves. The FSAR change utilizes the standard words for a pump that is normally operating (predominately running) but may be shut down for periods of time to perform equipment rotation evolutions, testing, troubleshooting, maintenance, etc.

Summary of Evaluation:
The Reactor Makeup Water System contains two unit specific RMUW pumps and a common pump that can be aligned to either unit as required. The normal mode of operation is for two of the three pumps to be running on minimum recirculation flow with the third pump in standby. This activity involves changing the UFSAR and Plant Procedures to allow one of the two normally operating RMUW Pumps to be shut down during normal plant operation for equipment rotation. A plant operator would be required to locally stop one operating pump, perform the required valve manipulations for realignment, and start the other pump. If the standby pump failed to start, the operator would be required to realign the valves and restart the previously running pump. The initial and final configurations of the system are unchanged by this activity. Historical evidence suggests that manipulation of system diaphragm valves to perform realignments and tests while the RMUW pumps are running significantly increases the failure rates for these valves. By securing one RMUW pump prior to performing the equipment alignment change, the valves are exposed a decreased quantity and severity of pressure transients. Stopping the pumps during the swap was evaluated and found to increase the likelihood of Reactor Makeup Water System failure by less than a factor of two per normal six week train swap interval.

There are no demands on the RMUW system that require instantaneous makeup to be provided. A review of all of the transients and requirements that would be made on the RMUW system show that it is acceptable to have one of the two operating RMUW pumps out of service for equipment rotation, since a plant equipment operator (PEO) would be present to restore the locally controlled pump to service if it became necessary. The presence of an operator would offset the impact on the assumed minimum operator action time of 30 minutes to provide manual make-up. The ability to mitigate loss of inventory events is not significantly affected. Based on discussions with Operations personnel, skills possessed by plant operators will ensure that tank levels are adequate prior to degrading any inventory makeup source.

This evaluation shows that it is acceptable to have one of the two operating RMUW pumps out of service for short periods to perform evolutions, testing, troubleshooting, maintenance, etc. Therefore, "normally operating" is the proper description of the method of pump operation.

This change will therefore improve the performance and reliability of the diaphragm valves with a no more than a minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety.

There are no credible accidents that could be initiated by shutting down one of the two operating RMUW pumps for equipment rotation evolutions, testing, troubleshooting, maintenance, etc. The shutting down of a RMUW pump will not affect the probability of a Licensing Basis Accident or the course of a Licensing Basis Accident.

It is concluded that this activity may be implemented in accordance with site procedures without NRC approval.

Evaluation Number: 59EV-2001-001672-01-00 **Unit 2**
Revision 0

Activity Description:
Plant design changes cover the first phase replacement of the selected turbine-generator (TG) analog control systems with a new digital control system. This upgrade is required to improve long term TG reliability and to eliminate the obsolescence issues associated with the control systems.

The following turbine generator systems as described in Section 10.2 of the UFSAR was migrated to the new digital control system via the above plant design changes.

Electro Hydraulic Turbine Controller (EHC)
Turbine Stress Evaluator (TSE)
Speed Target Unit (STU)
Seal Steam Controller (SSC)
Generator Temperature Control (GTC)
Leakage Water Return Control (LRC)
Moisture Separator Reheater (MSR)
Thyristor Voltage Regulator (TVR)

The operator interface to the new digital system is via operation and monitoring process control and information system and consists of two redundant computer-based workstations with two Video Display Units (VDU) each (total four) in the control room. This allows the plant to be operated, visualized and monitored centrally. The digital controls consist of dual redundant process computers. These computers handle both system control and system monitoring. The failure of any single component of the Operating and Monitoring (OM) system does not prevent safe operation of the turbine-generator. All migrated turbine-generator control systems are operated using screen-based soft controls.

All main control board equipment associated with the replaced turbine-generator control systems and generator exciter voltage regulator system (TVR) are removed from the main control board with their functions migrated to the new OM system. This includes system controls, monitoring of process parameters, and alarm functions. The turbine trip logic and the control interfaces with the Reactor Protection System (RPS) are not affected by these design changes.

LDCR-SA-2002-030 describes the changes to the UFSAR required to address the Licensing Basis Document changes for these activities.

Summary of Evaluation:
The operator impact of operating the Turbine Controls and Generator Thyristor Voltage Regulator from the re-designed control workstation is significant. Its adverse impact is less than minimal. All Control Room operator interface devices formerly located on control boards as control switches, analog indicators, alarms, etc., have been replaced with video display terminals, keyboards, and mouse devices located on two consoles in the Control Room. Engineering Evaluations have been performed to document acceptability of those critical aspects

of these activities as required by industry regulations and by industry technical guidelines. The Human System Interface (HSI) has been properly addressed through design and testing of the OM Screens, procedure development, and simulator operator training. Access to the control system through the OM station is limited to authorized personnel by the use of access passwords. System Software/Hardware attributes have been properly addressed through engineering evaluation, design and testing in accordance with industry guidelines to ensure safe and reliable system operation.

The new upgraded digital control system for the turbine/generator controls and generator exciter voltage control systems serve the same function as the existing analog systems. The consequences of an equipment malfunction are the same as those of the equipment being replaced. The reliability of the controls for the affected systems will be increased because of the redundancy in the software, enhancement of the automatic control functions and added redundant instrumentation. There are no new accidents, failure modes, or malfunctions created by this change. Therefore, prior NRC approval is not required for these proposed plant activities.

Evaluation Number: 59EV-2002-000129-01-00 **Unit 2**
Revision 0

Activity Description:
The activity describes the replacement of the local Chiller Control Panels for the Non-Safety Related Ventilation Chillers (X-01 through X-04) with a local digital (microprocessor based) control system. Additional plant parameters are also being added to enhance the control and monitoring capabilities of the ventilation chiller packages.

There is one digital control panel installed on each (total four) chiller. The panels are mounted locally at each chiller in the Auxiliary Building at elevation 873'-6". Each panel will operate one chiller, provide information to maintenance personnel and be installed with the ability to upgrade the non-safety chilled water system in order to monitor it as a whole. The digital controls consist of an "OptiView" digital panel that provides the capability to monitor several operating parameters at once and will be operated using a screen-based soft controls system as well as new electronic instrumentation.

Each chiller package will perform its intended design function independently. Thus, failure of any single component of the "OptiView" system for a particular chiller does not prevent safe operation of the remaining chillers.

There is no Control Room (control board) equipment associated with the chiller digital control panels. There will be local system controls, monitoring of process parameters, and alarm functions. Operations and Maintenance personnel will have the ability to monitor the chillers and specific parameters as the chillers are expected to be monitored easier, provide sufficient trending information as to be able to troubleshoot inadvertent trips and provide trending information to schedule down times and routine maintenance. This modification is anticipated to be installed on the remaining non-safety related chillers (X-05 through X-09) in the future with provisions for future monitoring of the the entire non-safety related chilled water system from predetermined (not currently defined) central locations.

Summary of Evaluation:
The Operator impact of operating the chillers via this new "OptiView" digital control panel is significant. Its adverse impact is less than minimal. All Operator interface devices formerly located on local analog panels (e.g. switches, analog indicators, alarms, etc.), have been replaced with touch sensitive membrane keypads and video display terminals mounted seismically at each chiller.

NEI 01-01, Appendix A guidance has been used to address the critical aspects of the digital control panels.

The Human System Interface (HSI) has been properly addressed through design and testing of the "OptiView" Graphic Control Center, procedure development, and Operator training. Access to the control system through the Graphics Panel is limited to authorized personnel by the use of access passwords. System Software/Hardware attributes have been properly addressed through

engineering evaluation, design, and testing in accordance with industry guidelines to ensure safe and reliable system operation.

The new upgraded digital control panels serve the same function as the existing analog systems. The consequences of an equipment malfunction are the same as those of the equipment being replaced. The reliability of the controls for the affected systems will be increased because of the enhancement of the automatic control functions and added electronic instrumentation. There are no new accidents, failure modes, or malfunctions created by this change. Therefore, prior NRC approval is not required prior to implementation of the proposed plant activities.

Evaluation Number: 59EV-2002-001062-01-00 **Units 1 and 2**
Revision 0

Activity Description:
Telescopic Jib Cranes were installed in the Containment Building for Unit 1 and Unit 2 in 1999 during 1RF07 and 2RF04, respectively. These new cranes operate in the same area of containment above Elevation 905 as the Polar Cranes where the possibility of crane to crane interactions exist. The basis for the modification being acceptable was that crane to crane interactions would be prevented by limit switches that control the movement of the Jib Crane boom so that interaction between the boom and the polar crane is precluded. Subsequently, two instances of crane to crane interaction have occurred.

The original design on both units is being modified to install an automatic Containment Crane Anti-collision System using digital controls to improve the current design for the Containment Jib Crane and the Polar Crane as corrective action for inadequacies in the original design. This system reduces the likelihood of collision between cranes by utilizing PLC digital control which normally prevents Containment Jib Crane operation from reaching the lowest Polar Crane equipment location, and prevents Jib Crane operation with the end of the boom within three feet of any object. The Jib Crane control design includes a moveable bypass key, normally located in the Polar Crane controls, which would allow the Jib Crane to be raised to a height at or above the Polar Crane; however, removal from the Polar Crane defeats the radio control to the Polar Crane bridge. With the key removed from the Polar Crane, full operation is still capable form the cab.

Units 1 and 2 were modified to install a Containment Crane Anti-Collision System on the Jib Crane and a permissive key to the Polar Crane radio controls during 1RF09 and 2RF07, respectively.

This 10CFR50.59 Evaluation was performed to address a corrective action issue statement which identified that previous evaluations did not adequately describe the Telescopic Jib Crane operation within Containment. Therefore, this 10CFR50.59 Evaluation provides supplemental documentation to previous 10CFR50.59 Reviews (SE-98-045 and SE-98-113) of the Jib Crane modifications.

Summary of Evaluation:
The FSAR design functions related to 10CFR50, Appendix A, General Design Criteria 2 (i.e., seismic design requirements) and General Design Criteria 4 with respect to the handling of heavy loads were adequately covered by the previous 10CFR50.59 Evaluations. The scope of this evaluation is to supplement the previous documentation with an evaluation of the corrective actions for the design inadequacies in the original design and statements in the 10CFR50.59 reviews that are related to it.

The design includes anti-collision design features which constitute an FSAR design function. The FSAR is being updated in accordance with NEI 98-03 Rev. 1 and RG 1.181.

The anti-collision design features use a PLC that receives and processes crane signals to limit operator control so the Jib Crane boom cannot be raised or extended to within one foot of the

lowest elevation of the Polar Crane cab and disables Jib Crane motion in any direction that places the horsehead of the boom within three feet of any object. The digital controls installed by this modification have been evaluated in accordance with EPRI TR-102348, Revision 1/NEI 01-01. The PLC is certified to be in conformance to technical specifications of internationally recognized electromagnetic emission and immunity standards and is installed in a grounded metal enclosure, with all outgoing cables installed in conduit. Therefore, there will be no adverse impact on any instrumentation and controls in the plant. There is no human-system interface with the exception of the permissive key and operator actions credited in the licensing basis are unaffected. Testing of the system addressed all operating conditions described in the system Software Requirements Specification, in normal and any potential abnormal conditions. No new failure modes were introduced by the new system.

This evaluation concludes that the combined removal of the upper auxiliary cranes, upgrade of the anti-collision design, and proper implementation of administrative controls correct the original design deficiencies and reduce the likelihood of interactions that would be adverse to nuclear safety functions.

Although the design and administrative controls cannot absolutely preclude any interactions, it is concluded that catastrophic failures that could result in multiple missiles have been reduced below the level considered credible in the licensing basis (i.e. comparable to other equipment).

Therefore, the Jib Crane installation will not result in a malfunction of an SSC important to safety of a different type than any previously evaluated in the FSAR and will result in no increase in likelihood of occurrence of a malfunction of an SSC important to safety previously evaluated in the FSAR.

Implementation and use of the telescopic jib cranes do not require prior NRC approval.

Evaluation Number: 59EV-2002-002151-01-00 **Units 1 and 2**
Revision 0

Activity Description:
The automatic turbine trip from high vibration on the primary water pump has a time delay upon receiving a two of two channel trip signal. The original design is for a 4 second time delay. The automatic trip delay is being extended from 4 seconds to an extended time (>2000 seconds) which effectively changes the automatic trip to an operator initiated manual trip. The trip will not reliably function at this extended time and will be non-functional. This will require the operator (which will take additional time versus the 4 seconds) to analyze the vibration condition and decide whether to initiate a manual trip or trip inhibit. This activity is being done to reduce unwarranted trips. The FSAR change will allow the trip to be either enabled or disabled.

Summary of Evaluation:
The operator impact of operating with the Primary Water (PW) Pump high vibration automatic turbine trip interlock defeated is the increased operator attention required when the pump vibration level goes into alarm status; however, this is minimal and preferable to a plant trip. The operator would now have to make the determination that the vibration level is significant in level and duration that manual tripping of the turbine should be initiated.

Diverse automatic tripping of the turbine, based on Primary Water Head Tank low level or Primary Water System low flow, is still provided to automatically trip the turbine. These two parameters are indicators of PW Pump performance. Additionally, a PW Pump high vibration alarm, as well as a sophisticated digital recorder, provide the operator with real time measurements of the PW Pump vibration status. A manual turbine trip switch is provided for operator use. Therefore, it can be concluded that the increase in the likelihood of a malfunction in the turbine trip logic from Primary Water Pump problems is less than a factor of two. In accordance with Section 6.2.2 of the 10 CFR 50.59 Resource Manual, this increase is minimal. Therefore, a License Amendment is not required.

Evaluation Number: 59EV-2002-002189-01-00 **Units 1 and 2**
Revision 0

Activity Description:
Four Thermal Relief Valves (namely 1/2CT-0005 & 1/2CT-0056) are to be temporarily gagged during plant operation as a compensatory action for a degraded and non-conforming condition. The basic function for these valves is an ASME CODE requirement to protect the tube side of heat exchangers CP1/2-CTAHCS-01 & CP1/2-CTAHCS-02 and associated piping from overpressurization due to thermal expansion. This could occur during maintenance activities and where isolation of the heat exchangers may be required. The basic Nuclear Safety Function of these valves is to maintain the system pressure boundary during and after an accident and it is this function which is degraded and requires compensatory action. The Containment Spray (CT) system will perform its Nuclear Safety Functions with the valves gagged. Gagging has no effect on system performance. Gagging these valves will reduce the likelihood of a loss of pressure boundary integrity in the CT system due to a stuck open relief valve and ensure the consequences of an accident or malfunction are not increased. Therefore, this function does not require evaluation under 10CFR50.59.

The design function of the relief valves to protect the tube side of heat exchangers from overpressurization, is a requirement per the 1974 ASME Code Section III Subsection NC 7000. This function may be called upon during maintenance activities where an unlikely event may be initiated for thermal pressure transients to occur in the system. In such a scenario, the relief valves may exceed their set pressure and consequent valve opening would prevent overpressurization. Gagging the valves would be adverse and is the subject of this evaluation. Therefore compensatory action to gag subject thermal relief valves is closely controlled by issuance and implementation of design change documents with appropriate notes added to affected vital station drawings. Plant operation and maintenance personnel working to these vital station drawings are required to remove the gags from the relief valves when maintenance is being performed on the heat exchanger or the heat exchanger is to be isolated for any reason.

This activity revises affected vital station drawings (flow diagrams) to identify the gagged valves and to provide a precaution.

Summary of Evaluation:
Compensatory action to gag thermal relief valves in the containment spray system for both units will be in place due to the recent failure of two of the valves to reseat following lifting during the recirculation of the RWST. Historical and plant computer data shows that when the valves lift during the recirculation of the RWST, pressure is not restored to levels low enough that would allow the thermal relief valves to reseat and thereby allowing flow from the Containment Spray (CT) system into Vents and Drains.

The thermal relief valves, 1/2CT-0005 and 1/2CT-0056, have two design functions:

1. In accordance with ASME III and RG 1.29, the relief valves maintain system pressure boundary during operation of the containment spray system. [FSAR Section 6.2.2.1 and 6.2.4.1.5]

2. In accordance with ASME, III thermal overpressure protection for the containment spray heat exchanger when it is isolated (valved out) for maintenance. [FSAR 6.2.2.2.1 and ASME III]

Gagging the subject thermal relief valves to maintain system pressure boundary during and after an accident is the compensatory action. The effect on ASME Code overpressure protection is the only other design function affected.

Although, gagging the valves would increase the likelihood of an inadvertent overpressure if the component were improperly isolated, the chance of this happening is negligible and would not result in more than a minimal increase in likelihood of a malfunction of the component because the sequence of necessary events would be highly unlikely. For this to occur, not only would a gross mistake have to occur, it would have to go undetected and it would have to have been so severe as to bring the component to the point of failure such that it would not be detected until after it were placed in service. Such a sequence of unlikely events could not cause a more than minimal increase in the likelihood of occurrence of a malfunction of an SSC important to safety.

It is concluded that these compensatory actions may be implemented in accordance with site procedures without NRC approval.

Evaluation Number: 59EV-2003-001198-01-00 **Units 1 and 2**
Revision 0

Activity Description:
The fluid transient analysis as described in Section UFSAR Sections 3.9N & 3.9B were performed using the nuclear industry recognized computer code WATHAM. The output of this Code is a design input to piping stress analysis analyses used for piping and piping support analysis and design.

WATHAM is no longer readily available to CPSES and will be replaced with the equivalent computer code Hydraulic System Transient Analysis, commonly abbreviated as HSTA, version NE820. The proposed activity is the adoption of the HSTA computer code as an acceptable method for providing the water hammer forcing function design input to the dynamic piping stress analysis.

Summary of Evaluation:
The overall methodology for performing piping stress and support evaluations and analyses of flow transients in liquid piping systems (e.g., water hammer events) includes the use of computer codes such as ME101. One of the design inputs to ME101 is the time history forcing function of the postulated flow transient. The overall analysis methodology involves the use of design input fluid transient forces from the WATHAM computer code. The proposed activity would change an element of the overall analysis methodology, previously reviewed and approved by the NRC in the CPSES SER (NUREG-0797), by providing an alternative to the WATHAM computer code with the equivalent code, Hydraulic System Transient Analysis (HSTA). Therefore, it is necessary to demonstrate that these two codes provide results that are conservative or essentially the same.

The WATHAM Code is no longer accessible or readily available to CPSES. HSTA is used to analyze flow transients in liquid piping systems and generate the piping segment time history forcing functions used as design input into the piping stress dynamic analysis code (e.g., ME101). The HSTA code utilizes the same finite difference solution of the method of characteristics (MOC) described in UFSAR Appendix 3B.9 as is used in WATHAM. Relative to the generation of the design input to the dynamic stress analysis analyses, both HSTA and WATHAM perform similar functions. Both computer codes are industry recognized codes for this application.

The comparison of the WATHAM computer code with the HSTA computer code is demonstrated in EPRI Report NP-6766 "Water Hammer Prevention, Mitigation, and Accommodation". The HSTA computer code is currently used in the nuclear industry (see, for example, Palo Verde Nuclear Generating Station's UFSAR Section 6.5.2.8, where HSTA is described as used to develop the time history forcing functions for water hammer-induced piping stress analyses of the Containment Spray System. Another example is GL 96-06 Fan Coolers Water Hammer analysis performed using HSTA and was approved by the NRC for the Arkansas Nuclear One, Units 1 & 2 - Completion of License Action for GL 96-06, "Assurance of

Equipment Operability and Containment Integrity During Design Basis Accidents", TAC Nos. M96775 and M96776 dated February 7, 2000).

From a review of the EPRI Report, it may be observed that the overall differences in results are within the programs' expected accuracies (approximately 10%, which is typical for this type of analysis). The individual results were independently reviewed and it was concluded that, for the stated application, the HSTA and WATHAM results are equivalent. Experience has shown that differences in the forcing function design input of the observed magnitude do not result in significant differences in the overall calculated dynamic piping stress and conclusions of the piping support evaluations. This conclusion is also consistent with conclusions presented in the EPRI report. Therefore, it is concluded that the "essentially the same" criterion is satisfied for this activity.

Based on the similarities and comparison of the above applications, the use of the HSTA computer code for providing the water hammer forcing function design input to the dynamic piping stress analysis does not result in a departure from a method of analysis previously approved by the NRC. Therefore, this proposed activity may be implemented without prior NRC approval.