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

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NO. 50-445 – UNIT 1, CYCLE 13 STARTUP REPORT

Dear Sir or Madam:

As an enclosure to this letter, TXU Generation Company LP (TXU Power) hereby submits the plant startup report for Unit 1, Cycle 13. The enclosed startup report addresses the tests that were performed to demonstrate that the unit operating conditions affected by the NSSS Upgrade Project remains within design predictions and specifications.

During the 12th refueling outage (1RF12), the NSSS Upgrade Project replaced all four steam generators and the reactor head in CPSES Unit 1. Upon completion of the modifications, Unit 1 returned to commercial power operation on April 20, 2007 and the return to service test program completed, with the exception of steam generator moisture carryover testing, on April 28, 2007. Moisture carryover testing for the replacement steam generators remains to be performed later in this operating cycle. A supplement to this report will be submitted each 90 days until such time as the replacement steam generator moisture carryover testing is completed.

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NRR

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

If you have any questions regarding these changes, please contact Mr. Robert Kidwell at (254) 897-5310.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC,
Its General Partner

Mike Blevins

By: Rafael Flores
Rafael Flores
Site Vice President

RJK
Enclosure – NSSS Upgrade Project Return To Service Test Program Summary Of Results

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

NSSS Upgrade Project Return to Service Test Program Summary of Results

May 7, 2007

D. T. Ross,

Operations Startup Manager

Approvals: PTRG Chairman D. T. R for R.R. BRABER

SORC Chairman

Executive Summary

The NSSS Upgrade Project Return to Service Test Program was created using regulatory guidance, industry precedent and best practices, as well as the CPSES Unit One Initial Startup Test Program defined in Chapter 14 of the FSAR. The baseline objectives of the program were to:

- Ensure Unit One continues to operate within the envelope of its design basis, post -modification
- Ensure new components perform as contractually warranted
- Verify that the modifications to the plant provide minimal challenges to the Control Room Staff during both steady state operations and normal operational transients.

Integrated Plant Operating Procedure, IPO-011A, "Plant Restart and Testing Following Steam Generator Replacement" was created to define performance of the testing required to return Unit 1 to full-power operation post-Steam Generator and Reactor Vessel Head replacement. In addition to testing identified by IPO-011A, some existing surveillance test procedures were used to perform normal instrument calibrations and data acquisition. Smartform SMF-2007-000434 was initiated to capture and document issues identified during testing, and evaluate them for resolution.

During performance of the full scope of Startup Testing, ten issues were identified six of which required some physical re-work and retest. All issues requiring rework involved wiring/cabling discrepancies. Five of the six were associated with the removal of the Feedwater Hammer interlocks. All of these were identified during performance of IPO-011A attachment 7.2.3, "Waterhammer Interlock Removal Test" which was created to ensure that components potentially affected by physical removal (primarily by the lifting/landing of wiring leads) of the interlocks would continue to function as designed, post-modification. The final cabling discrepancy identified caused reverse rotation of one of the two new CRDM air handling unit fans.

Westinghouse technical bulletin TB-06-17 alerted the project of sticking in new Control Rod Drive Mechanisms due to corrosion product accumulation post-Steam Generator replacement. IPO-011A attachment 7.2.12 "Control Rod Drive Mechanism Testing" was developed to identify and correct the condition should it occur. Sticking was observed in two of fifty three control rod drives during the initial attempt at rod withdrawal. In both cases, control rod withdrawal was successfully completed after several cycling attempts, as recommended by the technical bulletin.

The final two deficiencies identified during startup testing involved additional review of data and evaluation of acceptability. During performance of IPO-011A attachment 7.2.2 "Steam Generator Blowdown Test" plant conditions could not support steam generator blowdown flow described for piping vibration measurement. Vibration data was acquired on one loop with blowdown flow as originally specified, with data obtained on the other three loops at somewhat lower blowdown flow rates. Engineering analysis provided extrapolation of the vibration data obtained at the lower flow rates and evaluated the results, with all vibration falling well within acceptance criteria.

The final issue identified during startup testing was revealed during initial review of plant performance data gathered during IPO-011A attachment 7.2.9 "Large Load Reduction". While it initially appeared that acceptance criteria for reactor power undershoot after the large load reduction was not met, further

evaluation of transient data and other, non-test related plant conditions indicated that acceptance criteria was in fact met.

The NSSS Upgrade Project Return to Service Test Program was successfully completed on April 28, 2007. A moisture carryover test remains to be performed later in the fuel cycle. All acceptance and review criteria have been met. Interviews with the Control Room Staff indicate that the newly modified plant, behaves extremely well, and is characterized by smooth load ramps and very mild response to operational transients. No control system tuning adjustments were required during the full sequence of startup testing.

Testing Performed and Results Obtained

Containment Ventilation System

The Containment Air Recirculation and Cooling system air flow balance check was performed by System Engineering using engineering test procedure EGT-164. All as found readings were satisfactory and no balancing adjustments were required.

IPO-011A attachment 7.2.1 "CRDM Ventilation Test" defined required testing on the CRDM ventilation system and balanced non safety chilled water flow throughout containment. Acceptance criteria and results were as follows:

- Acceptance criteria: CRDM shroud air flow ≥ 48,000 cfm through each fan. Measured flow 1-01 fan = 52,220 cfm. Measured flow 1-02 fan = 52,180 cfm
- Acceptance criteria: CRDM shroud exhaust temperature ≤ 163°F. Measured temperature = 116°F and 118°F for the two indicators.
- Containment average temperature was verified to remain ≤120°F.
- Acceptance criteria: CRDM cooling coil chilled water flow 750 (±37.5 gpm) Measured flow = 735 gpm
- Acceptance criteria: Containment fan cooler chilled water flow 960 (± 48 gpm) Measured flow = 1000 gpm.
- Acceptance criteria: Neutron detector well cooler chilled water flow 50 (± 2.5 gpm) Measured flow = 50 gpm.

Steam Generator Blowdown System

IPO-011A attachment 7.2.2 "Steam Generator Blowdown Test" defined performance of Steam Generator blowdown system flow and vibration testing. All measured piping vibration levels were significantly less than the 0.5 ips acceptance criteria. The SG 4 data was acquired at the prescribed 600 gpm total flow. Subsequently, the Control Room staff requested that flow be reduced for the remaining three Steam Generators, due to the system being aligned to discharge to the turbine building sump (for elimination of high silica content in the steam generators). EVAL-2007-000434-02 evaluated the data and found through (in comparison to loop 4) extrapolation all vibration levels to be acceptable.

Total system flow capacity is required to be at least the capacity of the system prior to the steam generator replacement and ≥416 gpm (1% of feed flow) with no single loop providing more than 200 gpm flow. Total system flow equaled the pre-replacement system limit flow of 600 gpm with no single loop greater than 200 gpm.

Steam generator blowdown sample system flow rates were also verified to provide proper sample flow to chemistry instruments.

Control System Interlocks

Due to the change from a pre-heater to feed-ring design with the D-76 Steam Generators, the existing feedwater system water hammer interlocks were removed. To ensure equipment in various control and relay racks that may have been affected during interlock removal (due to shared terminal block locations of some wiring), IPO-011A attachment 7.2.3 "Waterhammer Interlock Removal Test"

performed an energized functional test of the remaining equipment. There were no specific acceptance criteria for this testing other than the component of interest functioned when commanded. The following are the discrepancies identified by the testing performed. (SMF-2007-000434 documents resolution of all test program discrepancies)

Section 8.1, Relay 1-HX/2136A found with an open coil. Work order 4-07-173489-00 replaced the failed coil. The retest was satisfactory.

Section 8.2, Relay 1-HX/2137B found with an open coil. Work order 4-07-173491-00 replaced the failed coil. The retest was satisfactory.

Section 8.3, Valve 1-HV-2185 did not open as required. Investigation revealed that leads in 1-CR-15 terminals TRA-7 and TRA-8 had been inadvertently spared. Work order 2-06-166049-00 was revised and the leads re-landed. During retest it was discovered that the indicating light, monitor light box indication and plant computer indication did not change state when the valve was opened. Further investigation revealed that all 8 conductors of cable EO118146C had been spared vice the 2 that feed the interlock circuit being removed. Work order 2-06-166030-00 was revised to re-land the other 6 conductors. Retest was satisfactory.

Section 8.8, 1-HXA/5366 would not function. Troubleshooting revealed an improper neutral circuit routing. Work order 2-06-166046-00 was revised to correct. Retest was satisfactory.

Steam Generator Water Level Control

Several test sections were performed at various power levels primarily for tuning purposes. The sections are listed in the order they were performed from lowest power to highest.

IPO-011A attachment 7.2.10, "Low Power SGWLCS Response" was performed at approximately 8% reactor power with steam generator water level control on the Feed Control Bypass valves. Level set point was altered in 5% step changes (down and then up). Acceptance criteria was: ≤ 4% overshoot or undershoot in narrow range SG level, with time to return level to set point within three control system loop time constants (36 minutes), and maintain level within 2% of set point steady state. At the recommendation of the Westinghouse 7300 system tuning engineer, only the SG 1 control valve was required to be dynamically tested, and dependant upon results, tuning changes or dynamic testing would be applied to the remaining Steam Generators. The loop 1 test results were: 1.2% level overshoot and 1.2% undershoot, 13 minutes to return to set point on the level decrease and 15 minutes on the level increase, and stable control at set point steady state. No tuning adjustments were required and no other Feed Control Bypass valves required testing.

IPO-011A attachment 7.2.4, "Transfer from Bypass to Main Feedwater Control" was performed directly following Low Power SGWLCS Response. Acceptance criteria was that the Main Feed Control Valves stabilized SG level within 2% of set point within 3 control loop time constants (10 minutes) following closure of the Feed Control Bypass Valves. The stabilizations occurred at 9, 8.5, 7.5, and 7.5 minutes for loop 1, 2, 3, and 4 respectively. No control loop tuning adjustments were required.

IPO-011A attachment 7.2.6, "SGWLCS Response at Power" defined performance of tuning at 30%, 50%, 80%, and 100% power plateaus. Acceptance criteria was only defined for the 100% power plateau. The lower power tests were optional and were to be performed (or not) based on the observed performance of the control system during power ascension. On the recommendation of the Westinghouse tuning engineer the loop 4 Feed Control Valve was dynamically tested at 30% to gain confidence in the tuning settings prior to high power operation. At 80% power the loop 3 Feed Control Valve was dynamically tested, requiring the system to respond to a 5% step change (down and up) in SG narrow range level. Acceptance criteria was: ≤ 4% overshoot or undershoot in narrow range SG level, with required time to return level to set point being within 3 time constants of the control circuit (10

minutes). Observed results: S/G level overshoot and undershoot of less than 1%. Time to stabilize was 7 minutes for the step down and 5 minutes for the step up. Additional testing at 80% power included (with all four Feed Control Valves in automatic) a 25 psid step change to feedwater pump (feedwater to steam header) d/p. Acceptance criteria: The system returns feedwater d/p to program within 3 time constants of the control circuit (6.7 minutes), and after returning to set point no pressure oscillations greater than 45 psid exist. Observed results: Feedwater d/p returned to program in 6 minutes and no pressure oscillations were observed.

Feed Control Valve positions were measured at 100% power and required to be less than 80% of full stroke. The loop 2 Feed Control Valve was measured to be farthest open at 77% of full open. No tuning adjustments were required.

Atmospheric Relief Valves

IPO-011A attachment 7.2.11 "Atmospheric Relief Valve Functional Test" was performed to functionally test operation of the ARVs after the addition of redundant powered solenoid valves and switches to their control systems. In addition, new reference stroke times for the ARVs were obtained using the new control switches and solenoid valves. These reference values were used to determine acceptance criteria for future in-service testing per the ASME OMa code. The valves were determined to stroke acceptably with no abnormalities observed in the control circuits.

Control Rod Drive Mechanisms

IPO-011A attachment 7.2.12 "Control Rod Drive Mechanism Testing" was performed to verify the integrity and routing of the new CRDM cabling and connectors and the new Digital Rod Position Indication (DRPI) cabling and connectors. Additionally the new CRDMs were exercised per the recommendations of Westinghouse technical bulletin TB-06-17. The technical bulletin advised that sticking of new CRDMs has been observed at other facilities likely caused by iron oxides created when the RCS is open to atmosphere for an extended period of time (as during SG replacement). The iron oxides are then drawn into the mechanisms when the magnets are initially energized. Exercising the mechanisms releases the iron oxides back into the reactor coolant to be removed by the system demineralizers and filters. Rods H-10 and M-2 did not initially move when commanded individually. As expected, after several attempts at rod withdrawal the rods moved normally. Step trace data was taken and no further abnormalities were observed. All rods were fully withdrawn and inserted with the plant in cold shutdown (mode 5) and again at normal operating temperature and pressure (mode 3).

Plant Thermal Expansion (cold and hot gap) measurements

Piping and component supports affected by the SG replacement were measured by Westinghouse Engineering to verify the components' thermal expansion was as predicted. Additionally, observations were made to verify no binding existed, that SG upper and lower restraint (bumper) gaps were within design tolerances, and that snubbers remained within operational strokes. No binding was observed, no changes were required to snubber positions, and minor (< 1/8 inch) adjustments were made to eleven of twenty four bumper gaps.

Reactor Coolant System Flow Measurements

INC-7018A "RCS Flow Measurement Test" was performed at the 80% power plateau to measure RCS loop and total flow. Acceptance criteria: total RCS flow ≥ 389,700 gpm. As predicted RCS total flow increased from 407,546 gpm before SG replacement to a measured value of 415,790 gpm after SG replacement.

Main Steam System flow

IPO-011A attachment 7.2.7 "Steam Flow Calibration" was performed at the 0%, 30%, 50%, 80%, and 100% power plateaus to determine the new main steam flow transmitter zero points and span. Several adjustments were made to each indication loop with all channels indicating within ± 1.0% of calculated steam flow at 100% power when testing was complete.

RCS and Main Feedwater piping vibration measurement

IPO-011A attachment 7.2.8 "Vibration Testing of Reactor Coolant and Main Feedwater" was performed to gather RCS loop piping vibration data with the plant in mode 5 and again with the plant at normal operating pressure and temperature in mode 3. Acceptance criteria ≤ 0.5 ips vibration in mode 3 with four reactor coolant pumps running. All observed data met the acceptance criteria with the highest recorded vibration reading of 0.22 ips on loop 3.

Main Feedwater piping vibration was measured at 15%, 40% - 50% and 100% power with remote reading sensors. Acceptance criteria for all power plateaus: 3.0 ips vibration. All recorded data met the acceptance criteria with the highest observed vibration of 0.134 ips on loop 2 at 100% power. Loop 1 feedwater vibration data was not measured due to instrumentation failure. EVAL-2007-001413-01 dispositioned this as acceptable based on observed conditions on the other three feedwater lines.

Integrated System Testing

IPO-011A attachment 7.2.5 "10% Load Swing Testing" defined performance of 10% (120 MWe) step load changes at the 30%, 50%, 80%, and 100% power plateaus. The tests included verification of plant system interaction and automatic control system response, with subsequent control system tuning as required. The 30%, 50%, and 80% power tests were optional based on observed system response during power ascension.

Acceptance criteria were as follows:

- No reactor or turbine trip.
- No Safety Injection initiation.
- No SG or Pressurizer safety valve lift.
- No SG ARV or Pressurizer PORV lift.
- No manual intervention required to stabilize the plant.
- Reactor power overshoot and undershoot ≤3%.
- No sustained or divergent oscillations in steam flow, feed flow, RCS pressure, feed header pressure, steam header pressure, pressurizer level, RCS Tavg, or SG levels.

Results of the 90 MWe step load reduction performed at 80% power: no protective system, or safety valve or relief valve actuations occurred. Reactor power undershoot was 1.8%, no manual intervention was required and no system oscillations occurred.

Results for the 90 MWe step load increase: no protective system, or safety valve or relief valve actuations occurred. Reactor power overshoot was 2.17%, no manual intervention was required and no system oscillations occurred. No tuning adjustments were required.

IPO-011A attachment 7.2.9 "Large Load Reduction" defined performance of a 25% (275 MWe) step load reduction from an initial power level of 1000 MWe. Acceptance criteria were as follows:

- No reactor or turbine trip.
- No Safety Injection initiation.
- No SG or Pressurizer safety valve lift.
- No manual intervention required to stabilize the plant.
- Reactor power undershoot ≤3%.
- No sustained or divergent oscillations in steam flow, feed flow, or SG levels.

The results indicate very smooth response by the plant. Automatic extraction steam isolation to the high pressure feedwater heaters was anticipated based on previous (pre-SG replacement) plant performance and some amount of secondary system water hammer was expected. During the test, low pressure feedwater heater 3B was the only heater to isolate on high water level as extraction steam pressure decreased coincident with turbine load, causing flashing in the heater. Walk downs of secondary plant equipment indicated that water hammer was very mild and no damage occurred. No protection system actuations occurred, no safety valves lifted, no manual intervention was required, reactor power undershoot was 3%, and no oscillations were observed. Initial data review suggested that reactor power undershoot may have been greater than 3%. EVAL-2007-000434-03 documents additional review of data and analysis of plant conditions, and evaluated that testing results were as expected and all acceptance criteria were met.