UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-8064

March 8, 2000

Mr. C. L. Terry
TXU Electric
Senior Vice President & Principal Nuclear Officer
ATTN: Regulatory Affairs Department
P.O. Box 1002
Glen Rose, Texas 76043

SUBJECT: NRC INSPECTION REPORT NO. 50-445/99-19; 50-446/99-19

Dear Mr. Terry:

This refers to the routine resident inspection conducted on December 26, 1999, through February 12, 2000, at the Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed report presents the results of this inspection.

During the 7-week period covered by this inspection, your conduct of activities at the Comanche Peak facility was generally characterized by safety conscious operations, sound engineering and maintenance practices, and careful radiological work controls.

Based on the results of this inspection, the NRC has determined that one Severity Level IV violation of NRC requirements occurred. This violation is being treated as a noncited violation (NCV), consistent with Section VII.B.1.a of the Enforcement Policy. This NCV is described in the subject inspection report. If you contest the violation or severity level of this NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station, Units 1 and 2, facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if requested, will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Joseph I. Tapia, Chief
Project Branch A
Division of Reactor Projects

Docket Nos.: 50-445
50-446
License Nos.: NPF-87
NPF-89

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NRC Inspection Report No.
50-445/99-19; 50-446/99-19

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-445 50-446
License Nos.:	NPF-87 NPF-89
Report No.:	50-445/99-19 50-446/99-19
Licensee:	TXU Electric
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56 Glen Rose, Texas
Dates:	December 26, 1999, through February 12, 2000
Inspectors:	Anthony T. Gody, Senior Resident Inspector Scott C. Schwind, Resident Inspector
Approved By:	Joseph I. Tapia, Chief, Project Branch A

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Comanche Peak Steam Electric Station, Units 1 and 2
NRC Inspection Report No. 50-445/99-19; 50-446/99-19

Operations

- Unit 2 experienced a momentary loss of power to both 6.9 kV Class 1E safeguards busses while operating at 100 percent power. This resulted in an automatic actuation of all three auxiliary feedwater pumps as well as both blackout sequencer trains. Due to inadequacies in Abnormal Condition Procedure ABN-601, operators placed the control switches for all three auxiliary feedwater pumps in pull-to-lock for approximately one minute and entered an immediate action statement of Technical Specification 3.7.5. The procedural inadequacies were a Severity Level IV violation which is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee's corrective action program as Smart Form SMF 2000-000061-00 (Section 04.1).

Maintenance

- The licensee completed repairs to the Unit 1 Feedwater Isolation Valve 1-03 hydraulic system at power, which required entry into a 4-hour shutdown action statement per Technical Specifications. Although the work was not expected to exceed the 4 hours, the licensee requested and was granted a Notice of Enforcement Discretion by the NRC in order to extend the allowed outage time to 24 hours. Maintenance personnel were trained on a mockup and were able to perform the work correctly and safely. An unanticipated complication was encountered during the maintenance when it was discovered that the vendor-supplied replacement o-rings were the incorrect size. The licensee was able to adequately resolve this issue; however, this delayed completion of the work by 2-3 hours. No violations of regulatory requirements were identified regarding the root cause of the hydraulic pump failure which necessitated the repair and issuance of a Notice of Enforcement Discretion (Section M1.3).

- The licensee was responsive to emergent 6.9 kV breaker issues by implementing effective short- and long-term corrective actions. Both safety-related and nonsafety-related breaker maintenance was conducted with quality and attention to detail (Section M2.1).

- A latent maintenance error in the 138 kV switchyard resulted in a loss of Transformer XST1 when a fault 21 miles from the plant occurred on the Stephenville transmission line. This resulted in an automatic transfer of power to the alternate source of power (Transformer XST2) for Unit 2 Class 1E Busses 2EA1 and 2EA2 which occurred as planned. The licensee's walkdown of the 345 kV switchyard to address potential generic implications of the event was not timely and was not effectively communicated to plant management. Nevertheless, the incremental impact of the latent maintenance error with respect to risk to the facility was small (Section M4.1).

Report Details

Summary of Plant Status

Both units operated at approximately 100 percent power for the entire report period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was safety-conscious. Specific events and noteworthy observations are detailed in the sections below. Through daily observations of control room activities, the inspectors concluded that both units were operated by knowledgeable operators using good self-verification techniques and communications. One isolated example where training and procedures did not adequately prepare operators is discussed in Section O4.1 below.

O2 Operational Status of Facilities and Equipment

O2.1 Plant Tours

a. Inspection Scope (71707)

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following areas of the plant:

- Units 1 and 2 containment buildings
- Units 1 and 2 safeguards buildings
- Units 1 and 2 control room
- Units 1 and 2 auxiliary building
- Units 1 and 2 fuel handling buildings
- Units 1 and 2 electrical control building
- Units 1 and 2 turbine buildings

b. Observations and Findings

Overall plant cleanliness and material condition continue to be good. No significant issues were identified. Some minor examples of inappropriately stored temporary equipment and improperly routed temporary power cords were identified and corrected quickly.

The inspectors toured both the Units 1 and 2 containment buildings during routine entries by the licensee. In general, material condition of equipment in the containment building was good. The inspectors observed a small number of minor borated water leaks, all of which were being tracked and periodically cleaned and monitored for corrosion. The 808 foot elevation of both containment buildings were free of debris and all permanently stored equipment was properly secured so as not to interfere with operation of the containment sumps. The inspectors observed that the Unit 1 condensate drip trays for the recently modified containment recirculation fan cooling coils appeared to have overflowed at one point, leaving residue on the floor of the 860 foot elevation. There was little water on the floor during the inspection. However, the condensate drip trays drain to a collection tank in containment which is monitored by the control room as one potential indication of system leakage inside containment. A clogged condensate drip tray drain would reduce the number of available reactor coolant system leakage indications. The licensee planned to determine the cause of the water on the floor during the next routine containment entry on February 22, 2000. During the Unit 2 containment building tour, the inspectors observed air noises coming from the pressurizer spray valve room (a locked high radiation area) and a system interaction issue between containment level Transmitter 2-LT-4781 and an adjacent hanging light fixture. The licensee determined that the Unit 2 Loop 1 pressurizer spray valve was oscillating slightly but was not an immediate problem and planned to monitor it. The potential system interaction problem was placed into the licensee's corrective action system and did not pose an immediate operability concern.

The inspectors conducted frequent tours of the control room to assess ongoing plant operations, operator knowledge, and attentiveness. The inspectors questioned operators on annunciators out of service, compensatory actions, and operator work-arounds. There were several compensatory actions in place for failed instruments in the Units 1 and 2 feedwater systems. Operators were knowledgeable of the nature of the equipment failures and of the required actions.

O2.2 Engineered Safeguards Features Walkdown

a. Inspection Scope (71707)

The inspectors conducted a walkdown of the accessible portions of the Unit 2 Trains A and B emergency diesel generators, residual heat removal pumps, auxiliary feedwater pumps, and spent fuel pool cooling systems.

b. Observations and Findings

Equipment was found in its proper standby condition and in generally good material condition. A small active leak was noted on a flange for Spent Fuel Pool Cooling System Valve XSF-0145 that had been previously identified by the licensee. The inspectors informed the licensee that a small amount of liquid was dripping on the floor. In response, the licensee immediately placed a catch basin under the drip to control the potential spread of minor contamination which was appropriate. The inspectors identified a sump in the Train B auxiliary feedwater pump room that had a small amount of loose insulation in it and informed the licensee. The licensee's investigation revealed that the sump did not serve a functional purpose. Nevertheless, the licensee informed the inspectors that the sump would be cleaned at a future date.

c. Conclusions

Engineered safeguards equipment was found in its proper standby condition and in generally good material condition.

O4 Operator Knowledge and Performance

O4.1 Operator Response to a Unit 2 Loss of Power to Transformer XST1

a. Inspection Scope (92901)

The inspectors conducted a followup review of a loss of power to Transformer XST1 which resulted in a momentary loss of power to both Unit 2 6.9kV Class 1E safeguards Busses 2EA1 and 2EA2.

b. Observations and Findings

On January 7, 2000, at 6:07 p.m., a fault on the Stephenville transmission line, approximately 21 miles from the plant, resulted in the redundant breakers (Breakers 7030 and 7040) supplying power to Transformer XST1 to open. Breakers 7030 and 7040 are designed, in part, to open if a fault is detected between the switchyard and the plant. Since Transformer XST1 is the normal supply of power to Unit 2 Trains A and B Class 1E Busses 2EA1 and 2EA2, they, in turn, momentarily de-energized. Both busses automatically transferred to Transformer XST2 as designed. Transformer XST2 receives power from the 345 kV switchyard. Both Trains A and B blackout sequencers (BOS) actuated as designed. With the exception of the cause of the event, namely the opening of both Breakers 7030 and 7040, all equipment operated as designed, including the actuation of both trains of motor-driven auxiliary feedwater pumps (MD AFWP) and the turbine-driven auxiliary feedwater pump (TD AFWP). A discussion of the cause of the loss of power to Transformer XST1, the generic implications, and immediate corrective actions taken by the licensee are discussed in Section M4.1 below.

Control room operators were quick to diagnose the loss of Transformer XST1 and entered Abnormal Conditions Procedure ABN-601, “Response to a 138/345 kV System Malfunction.” Operators verified that both main feedwater pumps remained in operation with normal steam generator levels and perceived the need to limit auxiliary feedwater (AFW) flow to the steam generators in order to prevent over-cooling the plant and a possible reactor power excursion. The reactor operator was instructed to stop the TD AFWP prior to completion of the BOS cycle. Since the BOS start signal was still present, the operator asked for clarification as to whether he should take the pump switch to “stop” or “pull-to-lock.” He was instructed again to stop the pump, which he did by taking the hand switches for both steam supply valves to the stop position. At this point, the operator lockout signal generated by both BOS trains had not yet cleared and the TD AFWP immediately re-started. The operator was then instructed to take the hand switches to the pull-to-lock position. When this was done, the pump was stopped. Shortly thereafter, the operator was instructed to take both MD AFWP’s to pull-to-lock.

All AFW flow to the steam generators was then secured. This resulted in entry into the action statement of Technical Specification 3.7.5 which requires the licensee to immediately initiate action to restore at least one train of AFW to an operable status. As soon as operators verified that the operator lockout signal had cleared on both BOS trains, the reactor operator placed all four hand switches in the “auto” position and restored the automatic start capability of the AFW system. The AFW system had been feeding all four steam generators for approximately one minute with no resulting change in reactor coolant system cold leg temperatures. The AFW pumps were in a pull-to-lock condition for approximately one minute while the BOS lockout signal cleared.

Section 3 of Procedure ABN-601 provides instructions for plant recovery from a blackout sequencer signal due to a fault in one of the switchyards. Step 3 of this section determines the status of the AFW system by verifying all three pumps are running and verifying adequate steam generator level. It then directs the operators to: (1) control AFW flow to maintain SG level, (2) verify adequate AFW flow available from MD AFWPs, and (3) place the affected TD AFWP steam supply valve hand switch(es) in PULL OUT. This section also includes a note stating, “Each steam supply valve to the TD AFWP opens on an Operator Lockout signal from its associated Blackout Sequencer (BOS). The BOS will also start the associated train MD AFWP. It may be necessary to limit the amount of Auxiliary Feedwater flow to the Steam Generators to prevent excessive RCS cooldown, overpower, or other adverse condition.” The note made no differentiation between an AFW system actuation at low power and one at full power nor did the procedure specify the method for controlling AFW flow. Therefore, with an overriding concern for plant cooldown, operators chose to control flow by securing the pumps rather than by throttling the flow control valves, which would have taken longer. Furthermore, the licensee had not previously conducted simulator training for a BOS or AFW system actuation at full power without a plant trip. This fact, when combined with the note in the procedure, led operators to believe that the AFW system should be secured as quickly as possible and caused them to place all three pumps in pull-to-lock prior to the operator lockout signal clearing on both BOS trains.

Despite the aforementioned procedure step which required operators to take the hand switches for the TD AFWP steam supply valves to pull-to-lock, and the procedure note stating that the valves open as a result of the operator lockout signal, operators initially attempted to secure the pump by placing the hand switches in the “stop” position while the operator lockout signal was still present. As soon as the switches were released, both steam valves began to reopen. The inspectors reviewed pump data obtained from the plant computer during this event which showed that the TD AFWP turbine speed continually decreased, despite the fact that the steam supply valves reopened momentarily before the switches were taken to pull-to-lock and that the overspeed trip setpoint of the turbine was not challenged.

Technical Specification 5.4.1 required that written procedures be established, implemented, and maintained as recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 6.a, recommends that procedures be established for combating events such as a loss of electrical power and/or degraded power sources. Abnormal Conditions Procedure ABN-601, “Response to a 138/345 kV System Malfunction,” was not adequate because it misled operators into completely securing the AFW system with a note that was not accurate for given plant conditions as well as providing no specific instructions on the method for controlling AFW flow during an unnecessary system actuation at 100 percent power. This also resulted in an unplanned entry into an immediate action statement of Technical Specification 3.7.5. Although disabling the automatic start function for all sources of AFW is typically a significant issue, the significance of this issue was low because of the short duration and because the operators' actions were overt and consistent with available guidance and previous training. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as Smart Form SMF 2000-000061-00 (NCV 50-445(446)/9919-01).

c. Conclusions

Unit 2 experienced a momentary loss of power to both 6.9 kV Class 1E safeguards busses while operating at 100 percent power. This resulted in an automatic actuation of all three AFWPs as well as both black out sequencer trains. Due to inadequacies in Abnormal Condition Procedure ABN-601, operators placed the control switches for all three AFWPs in pull-to-lock for approximately one minute and entered an immediate action statement of Technical Specification 3.7.5. The procedural inadequacies were a Severity Level IV violation which is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation was entered into the licensee’s corrective action program as Smart Form SMF 2000-000061-00.

O8 Miscellaneous Operations Issues (IP 92700)

O8.1 (Closed) Licensee Event Report (LER) 50-446/99004: lockout relay actuation caused the Unit 2, Train A, emergency diesel generator to start. This event was discussed in NRC Inspection Report 50-445(446)/99-11. No new issues were revealed by the LER.

O8.2 (Closed) Inspection Followup Item 50-445(446)/9809-01: operator awareness of the affect balance-of-plant efficiency has on the primary systems. The inspector reviewed the licensee's corrective actions following several past events which highlighted weaknesses in operators' knowledge of how the primary systems react to various transients in the turbine building. Operators were knowledgeable of how various turbine plant transients affected the primary systems. Training plans and simulator scenarios addressed the specific lessons learned from past transients and were conducted for both initial qualification and requalification training.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726, 62707)

In general, maintenance and surveillance activities were well performed by knowledgeable maintenance personnel. Quality and skill of the craft were evident in maintenance activities. With one exception noted in Section M4.1 below, effective communications and planning were evident in both maintenance and surveillance activities.

M1.2 Maintenance and Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspectors observed all or portions of the following maintenance and surveillance activities:

Unit 1, Train B solid state protection system logic test
Unit 1, Feedwater Isolation Valve (FWIV) maintenance
Unit 1, Train A motor-driven AFWP test
Unit 1, seismic grating clip installation
Motor Control Center XEB2-1 cleaning and inspection
6.9 kV breaker maintenance
Unit 2, Train A component cooling water system maintenance
Unit 2, Train A residual heat removal system maintenance
Unit 2, Train A safety injection system maintenance
Unit 2, containment pressure instrument calibration

Detailed observations are discussed in subsequent sections.

b. Observations and Findings

The inspectors observed several prejob briefs and found them to be thorough, focused on both plant and personnel safety, and conducive to questions from the participants. Both operators and maintenance personnel were knowledgeable of the maintenance and surveillance procedures, including applicable precautions and limitations. Appropriate plant and personnel safety precautions were observed. Operating equipment was monitored by both operators and engineers for abnormal conditions such as high vibration, temperatures, and lubrication. The inspectors found that both maintenance and operations personnel appropriately considered system interactions and that actions were well thought out prior to being taken. Radiological precautions were taken when appropriate.

Plant material condition continued to be good. The inspector observed maintenance personnel performing cleaning and inspections on a safety-related motor control center.

There was little dust and no debris inside the panels. Personnel performed a thorough inspection which revealed a loose auxiliary contact lead which was relanded per the preventive maintenance procedure. This condition was entered into the licensee's corrective action program for further investigation and trending.

c. Conclusions

Overall, maintenance and surveillance activities were conducted safely and in accordance with plant procedures. Maintenance personnel were knowledgeable of their procedures.

M1.3 FWIV 1-03 Hydraulic Pump Replacement

a. Inspection Scope (IP 92902)

The inspectors observed activities associated with replacement of the hydraulic pump on the Unit 1 FWIV 1-03 valve actuator. This included a review of the licensee's request for enforcement discretion in order to exceed the 4-hour limiting condition for operation allowed by Technical Specifications.

b. Observation and Findings

As documented in NRC Inspection Report 50-445(446)/99-18, the licensee experienced recurring problems with the hydraulic system on Unit 1 FWIV 1-03. This valve is equipped with a self-contained hydraulic/pneumatic system which uses hydraulic pressure to open the valve and nitrogen pressure to close the valve. The safety function of the valve to close on a Phase A containment isolation signal and was not affected by the degraded hydraulic system. The hydraulic portion of the system consists of a hydraulic pump, reservoir, and associated piping and control valves. While the pump is designed to maintain pressure in the valve actuator at a nominal 3600 psig, it acquired an undiagnosed problem which prevented it from developing the required shutoff pressure. This required the licensee to prime the pump approximately every 4 days by pressurizing the hydraulic reservoir with air to force hydraulic fluid through the pump. Although this did not affect the safety function of the valve, the licensee was concerned that the degraded condition of the hydraulic system could allow the valve to drift closed, thereby inducing a feedwater system transient and subsequent plant transient. Based on this, and on the risk analysis for a normal plant shutdown, the licensee believed it was more conservative to replace the hydraulic pump on line rather than performing a plant shutdown to effect repairs. Technical Specification 3.7.3 permits one of the four main FWIVs to be inoperable for a maximum of 4 hours prior to requiring a plant shutdown. Although maintenance personnel were able to complete the job within 2-3 hours on a mockup of the hydraulic system, the licensee requested enforcement discretion from the NRC prior to commencing the work so the 4-hour action statement could be exceeded as a continency for any complication encountered during the maintenance.

The inspectors reviewed the licensee's request for enforcement discretion after it had been approved by the Stations Operations Review Committee (SORC) and found it to be technically sound, with one exception. The compensatory actions section of the request only documented that the feedwater regulating valve also received a signal to close and was leak tested. Although important to the notice of enforcement discretion, this information was not considered a compensatory action. The inspectors discussed this with the licensee and determined that several compensatory actions being considered were adequate despite the lack of documentation. Furthermore, the inspectors observed the SORC meeting during which the request was reviewed and approved for submission to the NRC. The committee did not question the apparent lack of compensatory actions during this meeting and the request letter was approved by the committee without any major revision. After preliminary discussions with the NRC, the request was ultimately revised to describe the compensatory actions before it was officially submitted to the NRC. Following a review by the NRC staff, enforcement discretion to Technical Specification 3.7.3 was granted to extend the required shutdown action statement for this valve from 4 hours to 24 hours.

The inspectors reviewed the work package and observed the prejob brief and portions of the work. The scope of the work package included replacement of the hydraulic pump, the discharge check valve, and the hydraulic filter. During installation of the new components on the FWIV 1-03 hydraulic system, maintenance personnel noted that the o-rings from the vendor-supplied repair kit were a different size than the original o-rings and could not be used. The original pump o-rings were sized to accommodate a metal retaining ring in the seal along with the o-ring. The repair kit did not have the metal retaining rings and the new o-rings were too large to install along with a retaining ring. The licensee contacted the vendor and determined that o-rings of a suitable size and material were available onsite and that it was acceptable to reuse the original retaining rings. This delayed completion of the job from an estimated 3 hours to approximately 6 hours. This problem was not anticipated during the mockup training since the mockup did not have the metal retaining rings installed.

Following completion of the work, FWIV 1-03 was cycled twice to the 10 percent closed position. The hydraulic pump started as soon as the valve began to stroke open. It developed adequate hydraulic pressure and cycled off as expected several seconds after the valve strokes were complete. A compensatory action to periodically monitor the pump's performance was continued for several days afterward which confirmed that the repair had been successful.

Examination of the old hydraulic pump revealed a loose cap screw on the pump case which allowed air to be entrained in the hydraulic fluid and prevented the pump from developing its designed discharge pressure. No maintenance activities were identified which could have caused this cap screw to loosen since the pump was installed in 1998. Although it is likely that the condition existed when the pump was received from the vendor, the pump was nonsafety related and there were no applicable requirements contained in 10 CFR Part 50, Appendix B. Therefore, no violation of regulatory requirements was identified for the root causes necessitating the issuance of this Notice of Enforcement Discretion from Technical Specification 3.7.3.

c. Conclusions

The licensee completed repairs to the Unit 1 FWIV 1-03 hydraulic system at power, which required entry into a 4-hour shutdown action statement per Technical Specifications. Although the work was not expected to exceed the 4 hours, the licensee requested and was granted a Notice of Enforcement Discretion by the NRC in order to extend the allowed outage time to 24 hours. Maintenance personnel were trained on a mockup and were able to perform the work correctly and safely. An unanticipated complication was encountered during the maintenance when it was discovered that the vendor-supplied replacement o-rings were the incorrect size. The licensee was able to adequately resolve this issue; however, this delayed completion of the work by 2-3 hours. No violations of regulatory requirements were identified regarding the root cause of the hydraulic pump failure which necessitated the repair and issuance of a Notice of Enforcement Discretion.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 High Voltage ac Breaker Reliability

a. Inspection Scope (62707, 92902)

The inspectors reviewed the maintenance department SMART Team 3 actions taken to resolve a number of high-voltage electrical circuit breaker issues. In addition, the inspectors reviewed a SMART Team 3 self-assessment of the 6.9 kV breaker program completed on December 17, 1999. Several breaker refurbishment activities were also observed.

b. Observations and Findings

Overall, the inspectors found the SMART Team 3 responsive to emergent issues through effective short- and long-term corrective actions. Both safety-related and nonsafety-related breaker maintenance was conducted with quality and attention to detail.

The licensee’s 6.9 kV breaker program self-assessment found that breaker problems were occurring at a less frequent rate. This improvement was attributed to the increased effort in refurbishing aging breakers and on the small remaining population of breakers to be refurbished. Nevertheless, some problems with potential generic implications were identified with the refurbished breakers. These included issues associated with trip latch mechanisms, ball bearing type contact springs, and contact arm tightening procedures. The inspectors reviewed both the long- and short-term corrective actions for each of these issues.

The licensee found that breaker contact spring assemblies contain either ball bearings or bushings. On two occasions following breaker refurbishment, the ball bearing type breaker contact spring assembly failed. This prompted an immediate investigation into the extent that these ball bearing type assemblies were used in the plant and the failure mechanism. The licensee found that no safety-related breakers used the ball bearing type and that the failure occurred during infancy. Long-term corrective actions included a change to Electrical Manual Procedure MSE-C0-6305-R0-13, "6.9 kV 7.5HK Circuit Breaker Enhanced Maintenance," requiring the use of the bushing type contact spring assembly.

Two power operating mechanisms failed following refurbishment because of a manufacturing defect with the trip latch device. Both of these failures were identified during postrefurbishment testing and prior to placing the breaker into operation. The vendor was contacted by the licensee and it was later found that the manufacturing process resulted in inconsistencies in both the trip latch contact surfaces and dimensions. These manufacturing inconsistencies resulted in an infancy failure where the breaker would not stay closed. The licensee conducted an investigation which identified all the breakers in the plant that had the potentially defective trip latches and found that 8 Class 1E and 10 non-Class 1E breakers had trip latches from the failed trip latch population. The licensee found that the defective trip latch could be identified during a test which subjected the breaker to 30 consecutive cycles. Two of the Class 1E breakers were tested satisfactorily by performing 30 consecutive cycles of the breaker. The licensee verified that the remaining 6 Class 1E breakers had been cycled at least 30 times satisfactorily. Procedure MSE-C0-6305 was modified accordingly. The licensee informed the industry of the defective trip latch assembly by submitting an operating experience report and informed the inspectors that the vendor was considering submitting a report to the NRC pursuant to 10 CFR Part 21, "Reporting Defects and Noncompliance."

On December 14, 1999, after transferring Unit 2, Train A, switchgear from the preferred source (Breaker 2EA1-1) to the alternate source (Breaker 2EA1-2), the green open indicating light for Breaker 2EA1-1 was not illuminated as expected. Further investigation revealed that the indicating limit switch had overtraveled. Breaker 2EA1-1 was immediately replaced with a newly refurbished breaker and tested satisfactorily. The licensee found that the breaker jack shaft had been overtightened during refurbishment. This resulted in the need to readjust the linkage to the limit switch during refurbishment because the jack shaft was difficult to move and travel was limited. After the breaker was operated several times, the jack shaft travel became easier and traveled further. Once jack shaft travel increased to the point where the limit switch was driven further than designed, a loss of open indication resulted. The licensee conducted a visual inspection of all potentially affected Class 1E breakers and found no other cases where the limit switch linkage had been adjusted during refurbishment. Procedure MSE-C0-6305 was modified to incorporate clear jack shaft tightening procedures, a positive verification of jack shaft travel, and jack shaft force measurements.

c. <u>Conclusions</u>

The licensee was responsive to emergent 6.9 kV breaker issues by implementing effective short- and long-term corrective actions. Both safety-related and nonsafety-related breaker maintenance was conducted with quality and attention to detail.

M4 Maintenance Staff Knowledge and Performance

M4.1 Latent Maintenance Error Reduces 138 kV Switchyard Reliability

a. Inspection Scope (92902)

The inspector conducted a followup inspection on the causes of a loss of power to Transformer XST1, the normal source of power to Unit 2 Class 1E safeguards Busses 2EA1 and 2EA2.

b. Observations and Findings

As discussed in Section O4.1 above, on January 7, 2000, at 6:07 pm, a fault on the Stephenville transmission line approximately 21 miles from the plant resulted in both of the redundant breakers supplying power to Transformer XST1 (Breakers 7030 and 7040) to open. After inspecting the transmission line, the licensee attributed the fault to turkey buzzards (Cathartes aura). The 138 kV switchyard was designed to provide a reliable and redundant source of power to Transformer XST1. As such, the 138 kV switchyard relay protective scheme was designed such that a single transmission line fault beyond the switchyard would result in only that transmission line's breaker to open and not result in a loss of power to Transformer XST1. In the event that a fault were to occur between the switchyard and the plant, a directional ground fault relay detects the fault and opens Breakers 7030 and 7040, removing power from Transformer XST1. The licensee identified that this directional ground fault relay was misadjusted and in the closed position as if a fault had occurred between the switchyard and the plant. Further inspection revealed that the setscrew which prevents the relay from drifting out of adjustment had not been tightened. Because the misadjusted directional ground fault relay was closed when the fault occurred on the Stephenville transmission line, the 138 kV switchyard protective relay scheme reacted as if the fault was between the switchyard and the plant, opening Breakers 7030 and 7040. Once the directional ground fault relay was repaired, the 138 kV switchyard was restored and Transformer XST1 was realigned to supply power to Unit 2 Class 1E Busses 2EA1 and 2EA2.

On January 27, the inspectors observed a SORC meeting to review the proposed LER for this event. The inspectors noted that management was unaware of any immediate corrective action beyond what was completed in the 138 kV switchyard. The absence of discussion regarding the generic implications of the event was noted by the inspectors because directional ground fault relays installed in the 345 kV switchyard protection circuitry were of the same type and were maintained by the same maintenance organization. If these were also misadjusted, significant transients ranging from a unit trip to a complete loss of offsite power could be postulated with varying probabilities. The inspectors considered a verification of these relays important from both a plant reliability and safety perspective. This concern was discussed with licensee management at the conclusion of the SORC meeting.

On February 3, the inspectors walked down the 345 kV switchyard directional ground fault relays with maintenance management. The directional ground fault relay contacts were easily visible through a glass panel from outside the switchgear. The inspection was nonintrusive and completed within 10 minutes. None of the relay contacts were found closed indicating that they were in their proper alignment. The inspectors found that the licensee's inspection of these contacts took place on January 21. The inspectors questioned the licensee as to why such a simple but important inspection took 14 days to complete after the event. The licensee indicated that a work order had been written but was still in the planning stages when they decided to make an informal visual inspection. The licensee also indicated that the work order was still being planned to formally document the condition of the directional ground fault relays in the 345 kV switchyard. The inspector also noted that the January 21, 2000, inspection had not been communicated to the SORC nor was it mentioned in the approved LER.

The inspectors considered the significance of the latent maintenance error in the 138 kV switchyard by discussing its incremental impact on the core damage frequency with the licensee. With the directional ground fault relay misadjusted, the resultant instantaneous core damage frequency increased from a baseline of about $2X10^{-5}$ per year to about $6X10^{-5}$ per year. The inspectors agreed that this error was a fairly small increase in risk to the facility.

c. <u>Conclusions</u>

A latent maintenance error in the 138 kV switchyard resulted in a loss of Transformer XST1 when a fault 21 miles from the plant occurred on the Stephenville transmission line. This resulted in an automatic transfer of power to the alternate source of power (Transformer XST2) for Unit 2 Class 1E Busses 2EA1 and 2EA2, which occurred as planned. The licensee's walkdown of the 345 kV switchyard to address potential generic implications of the event was not timely and was not effectively communicated to plant management. Nevertheless, the incremental impact of the latent maintenance error with respect to risk to the facility was small.

M4.2 <u>Maintenance Rule Performance of the Radiation Monitoring System</u>

a. <u>Inspection Scope</u>

The inspector reviewed changes made to the performance criteria for the radiation monitoring system (RMS) since the Maintenance Rule baseline inspection was conducted in May 1998. The inspector also reviewed the basis for monitoring the system under paragraph a(1) of the Maintenance Rule and the effectiveness of the corrective actions taken for this system.

b. <u>Observations and Findings</u>

The RMS consists of approximately 137 subsystems which monitor radiation levels in various areas of the plant as well as process flows in certain mechanical systems. This information is collected and made available to operators in the control room and to the emergency response facilities via the PC-11 system. In some instances, output from this system is also used to perform process control functions such as redirecting or isolating system flows.

The RMS is not modeled in the plant's probabilistic safety analysis; therefore, a component reliability approach was used in establishing the performance criteria. Since a large number of the electronic components in this system have an unknown or unpredictable failure rate, the licensee determined that a predictive maintenance program was not feasible to specify component replacement intervals and designated these components as run-to-fail items. No formal evaluation, as discussed in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," or Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was performed prior making this designation. Nevertheless, the licensee did account for this in their Maintenance Rule implementation by including a repetitive functional failure rate in the performance criteria of no more than two functional failures within a 24-month period. This performance criteria did not consider if the failure was maintenance preventable. Therefore, component reliability factors that could have an adverse affect on overall system operability and would alert the licensee of the need to implement corrective actions were not adequately captured and trended by the maintenance rule. As a result, these component designations did not truly meet the definition of "run-to-fail" as used in NUMARC 93-01 or NRC Regulatory Guide 1.160.

The inspector reviewed a sample of condition reports regarding failures of the RMS covering a 2-year period and determined that the system failures were adequately reviewed against the Maintenance Rule. The system is currently monitored under paragraph a(1) of the Maintenance rule due to several repetitive failures, including failures of the containment air particulate monitor filter paper drives and failures of condenser off-gas monitors due to moisture in the sensing lines. In the case of the containment air particulate monitor, the failures were classified as maintenance preventable and corrective actions were implemented. Changes to the maintenance procedures were implemented which were effective in preventing repeat failures. In the case of the condenser off gas monitors, the failures were repetitive due to system design. Modifications were implemented in order to reduce the amount of moisture in the sample lines which included relocation of the monitors to a higher elevation relative to the main condensers. This modification was not entirely successful and leaks in the sample dryer condenser continued to develop. The licensee has entered this condition into their corrective action program as Smart Form SMF -1999-0001418-00 and continues to pursue a modification to reduce moisture levels in the sample lines.

c. <u>Conclusions</u>

The radiation monitoring system is currently monitored under paragraph a(1) of the maintenance rule due to continued problems with the main condenser off gas monitor. Corrective actions taken for this condition have not yet been effective. Corrective actions for other repeat failures of the system, including the containment particulate monitor filter paper drive, were reviewed and considered adequate. The condenser off gas monitor failures are being tracked through the licensee’s corrective action program as Smart Form SMF-1999-0001418-00.

III. Engineering

E1 Conduct of Engineering

E1.1 General Comments (37551)

In general, timely and appropriate engineering support was evident in day-to-day operations. Through interviews and direct observations, the inspectors found the system engineers aware of system performance and involved in the identification of adverse trends.

E2 Engineering Support of Facilities and Equipment

E2.1 Control Room Annunciator Design Change

a. Inspection Scope (37751)

The inspectors reviewed implementation of Design Change 12982 to improve the annunciator system power supply reliability.

b. Observations and Findings

Design Change 12982 modified the power transfer relay subassembly which is responsible for dc to ac power supply switching. Transistor failures had occurred during the switching process in the past due to relay contact arcing which allowed ac back feeding into the secondary of the transformer. This backfeeding phenomena resulted in an unacceptable inverter transistor failure rate. The inspector noted that the modification was installed quickly with almost no impact on operations. The design control package was clearly written and provided a concise, stand alone basis.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 Violation 50-445(446)/9802-06 (Closed): inadequate corrective actions resulting in a failure to identify potential operation of the safety injection pump motor outside its design basis. The inspector verified the corrective actions described in the licensee's response letter, dated June 5, 1998, to be reasonable and complete. No similar problems were identified.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

a. Inspection Scope (71750)

The inspectors observed radiological protection activities during routine tours and observation of maintenance and surveillance activities.

b. Observations and Findings

The inspectors observed several minor potentially contaminated borated water leaks which were adequately contained with drip containments by the licensee. Personnel entering the Units 1 and 2 containment buildings during power operations maintained dose as-low-as-reasonably-achievable and used appropriate contamination control practices.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

a. Inspection Scope (71750)

The inspectors observed security and safeguards activities during routine tours, at protected area access facilities, and at compensatory posts throughout the inspection period.

b. Observations and Findings

The inspectors found that security officers were attentive and conducted their duties in a professional manner. Central alarm station operators were alert and knowledgeable of current alarms and compensatory requirements. The licensee was responsive to special security needs as they arose.

F1 Control of Fire Protection Activities

F1.1 General Comments (71750)

During routine tours of the facility, the inspectors observed the control of fire protection activities. The inspectors observed that fire impairments were well controlled, that fire watches were present at all activities associated with welding or grinding, and that they were knowledgeable of their responsibilities. Proper precautions to prevent fires were observed during grinding and welding activities.

F2 Status of Fire Protection Facilities and Equipment

a. Inspection Scope (71750)

The inspectors observed a Unit 1, Train B switchgear room fire suppression deluge valve test.

b. Observations and Findings

The inspector observed fire protection technicians performing a test of the Unit 1, Train B, switchgear room fire suppression deluge valve. The technicians were knowledgeable regarding the system design and operation as well as the test procedure and expected system response during testing. The inspector also reviewed the test procedure and the design of the deluge valve and concluded that the test was adequate for demonstrating operability of the valve.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of the routine resident inspection to members of the licensee's management team on February 17, 2000. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Blevins, President, Nuclear Operations
R. D. Carver, Nuclear Overview Manager
T. P. Clouser, Chemistry and PROMPT Team Manager
J. L. Barker, Engineering Overview Manager
M. Lucas, Maintenance Manager
C. Cotton, Operations
A. B. Hall, Operations OVerview Manager
S. Ellis, Shift Operations Manager
M. Sunseri, Training Manager
D. Goodwin, SMART Team 2 Manager
T. A. Hope, Regulatory Compliance Manager
S. Smith, SMART Team 3 Manager
D. W. Snow, Regulatory Compliance
M. W. Sunseri, Nuclear Training Manager
J. A. Taylor, Design Basis Engineering Supervisor
N. Terrel, Reactor Engineering
J. C. Hicks, Regulatory Compliance
B. Mays, Engineering Programs Manager

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-445(446)/9919-01	NCV	Inadequate abnormal condition procedure for loss of power to 6.9 kV Class 1E safeguards busses.

Closed

50-445(446)/9919-01	NCV	Inadequate abnormal condition procedure for loss of power to 6.9 kV Class 1E safeguards busses.
50-446/99004	LER	Lockout relay actuation caused Unit 2, Train A emergency diesel generator to start.
50-445(446)/9809-01	IFI	Operator awareness of the affect balance of plant transients have on the primary.
50-445(446)/9802-06	VIO	Inadequate corrective actions resulting in the failure to identify potential operation of the safety injection pump motor outside it's design bases.

LIST OF ACRONYMS USED

AFW	auxiliary feedwater
BOS	blackout sequencer
CFR	Code of Federal Regulations
FWIV	feedwater isolation valve
IFI	inspection followup item
LER	licensee event report
MD AFWP	motor-driven auxiliary feedwater pump
NCV	noncited violation
RCS	reactor coolant system
RMS	radiation monitoring system
SORC	station operations review committee
TD AFWP	turbine-driven auxiliary feedwater pump
VIO	violation