ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-445 50-446
License Nos.:	NPF-87 NPF-89
Report No.:	50-445/99-16 50-446/99-16
Licensee:	TXU Electric
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56 Glen Rose, Texas
Dates:	October 3 through November 13, 1999
Inspectors:	Anthony T. Gody, Senior Resident Inspector Scott C. Schwind, Resident Inspector
Approved By:	Joseph I. Tapia, Chief Branch A

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Comanche Peak Steam Electric Station, Units 1 and 2
NRC Inspection Report No. 50-445/99-16; 50-446/99-16

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- The licensee did not implement a pre-established contingency plan to refill the reactor coolant system to 80 inches above the core plate if reactor coolant system delays were experienced. A work activity on the reactor vessel head delayed the vacuum fill procedure for 14 hours and unnecessarily increased the time spent in midloop. This condition slightly increased the overall outage risk profile (Section O1.3).

Maintenance

- The licensee made two separate errors during fuel handling activities: (1) the positioning of a thimble plug in the incorrect fuel assembly and (2) a sequence error while reloading the Unit 1 core. Both of these errors were attributed to a lack of attention to detail and ineffective independent verification. In both cases, personnel discovered their own errors, suspended activities, and notified their supervisors. The failure to properly implement the fuel shuffle sequence plan in accordance with plant procedures was a violation of Technical Specification 5.4.1. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The incorrect placement of the thimble plug and the core reload sequence error were entered into the licensee's corrective action program as SmartForms SMF-1999-002717-00 and SMF-1999-002905-00, respectively (Section M1.3).

- On May 10, 1999, the licensee identified that the power-operated relief valve actuation circuits were not properly tested as required by Technical Specification Surveillance Requirements 4.4.4.1 and 4.4.8.3.1. The missed surveillance was reported in accordance with 10 CFR 50.73(a)(2)(B) in Licensee Event Report 50-445;446/99-001-00. Surveillance procedures were appropriately modified and the untested contacts tested satisfactorily during the next shutdown. Technical Specification 3.4.8.3 required the power-operated relief valves to be operable in Modes 4, 5, and 6 for low temperature overpressure protection and Technical Specification 3.4.4 required the power-operated relief valves to be operable in Modes 1, 2, and 3 for overpressure protection. Due to the location of the untested contacts, the licensee concluded that the power-operated relief valves remained operable for Modes 1, 2, and 3 because the untested contact did not preclude manual operation of the relief valves. Although the automatic mode of operation was preferred, there was no Technical Specification restriction to rely on manual operation of these valves while in Modes 1, 2, or 3. 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 SmartForm SMF-1999-001289-00 (Section M8.1).

Engineering

- Three spring can supports on the Unit 2 Feedwater Heater 2-4A drain pipe failed, leaving 49 feet of the 10-inch pipe unsupported. The potential failure of this pipe would have resulted in a minor increase in core damage frequency. Nevertheless, it posed a serious personnel hazard and the licensee's immediate corrective actions were appropriate. Long-term corrective actions were still being evaluated in order to preclude similar failures in other secondary systems (Section E2.1).

Report Details

Summary of Plant Status

Unit 1 began the report period in a refueling outage with the core offload in progress. On October 29, 1999, Unit 1 was returned to service. Unit 1 reached 100 percent power on November 4 and remained at essentially 100 percent power for the remainder of the report period. Unit 2 remained at essentially 100 percent power 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 professional and safety-conscious; 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. Although the planning and preparation for the Unit 1 outage was thorough and properly considered risk, an unplanned extension of the postrefueling midloop occurred for which pre-established contingency plans were not implemented. This resulted in an unnecessary and small increase in risk to the facility.

O1.2 Unit 1 Reactor Startup

a. Inspection Scope (71707)

The inspector observed the licensee start up the Unit 1 reactor following the seventh refueling outage.

b. Observations and Findings

On October 29, 1999, at 12:21 a.m., the licensee commenced a reactor startup of Unit 1 following its seventh refueling outage. The pre-evolution briefing conducted prior to startup was comprehensive and included input from operations department management, training, and reactor engineering. Lessons learned from previous startups and industry experience were discussed thoroughly. The startup was performed by sequentially withdrawing all control rods then diluting to criticality. Operators appropriately used three-way communications, self-checking and peer-checking and were attentive to the control boards during the startup. The unit supervisor monitored all reactivity changes. While withdrawing the Control Bank A rods, operators noted that the group 2 rods stepped out just before the group 1 rods. The rod groups remained within ½ step of each other. Operators appropriately stopped rod withdrawal and conferred with reactor engineering and system engineering in determining that there was no operability concern and continued with the startup. This anomaly was attributed to the manner in which the startup procedure tests the rod deviation alarm. The condition was entered into the corrective action program as Smart

Form SMF-1999-3059-00. The reactor achieved criticality at 2:30 a.m., at which point power was leveled and preparations were made for low power core physics testing.

On the evening of November 1, 1999, the main generator was synchronized to the grid. Ten minutes later, operators manually tripped the main turbine due to rapidly increasing temperatures on the generator primary water system. The licensee quickly identified a valve in the system that had not been properly repositioned following a maintenance activity. The valve was repositioned and the main generator was once again synchronized to the grid. Power ascension continued without any further difficulties and Unit 1 achieved 100 percent power on November 4.

c. Conclusions

Operators were attentive to the control boards and used good self-verification and peer-checking techniques during the Unit 1 reactor startup following the seventh refueling outage. Operators appropriately responded to anomalies with the rod control system and the main generator primary water system during the startup and power ascension.

O1.3 Unit 1 Midloop Operations

a. Inspection Scope (71707)

The inspectors observed control room operators drain the Unit 1 reactor coolant system (RCS) to a midloop condition following core reload during the refueling outage.

b. Observations and Findings

Prior to entering the RCS midloop condition, the inspectors reviewed both routine and abnormal operating procedures and found them to be sufficient to operate the facility safely in the reduced inventory condition. Additionally, the inspectors reviewed the licensee's risk assessment and defense-in-depth contingency plans and found them to be realistic and appropriately based on maintaining an adequate level of protection for public health and safety. Operators and shift management were found to be knowledgeable of the indications of residual heat removal pump cavitation and were properly trained on the potential transients which could occur.

On October 23, 1999, control room operators drained the Unit 1 RCS to a midloop condition in order to remove nozzle dams from Steam Generator 1-03. A conservative letdown rate was established and operators monitored RCS level on all available instruments. A dedicated operator was used to monitor the residual heat removal system which allowed the reactor operator to focus on level indications.

During and prior to midloop plant conditions, the inspectors conducted walkdowns of the protected defense-in-depth equipment and found them to be in their proper standby condition and appropriately roped off to prevent unauthorized access.

The inspectors observed that midloop conditions were unnecessarily extended for 14 hours to conduct reactor vessel head work. The licensee had planned to complete the reactor vessel head assembly work in parallel with the 22 hour midloop window, which should have been completed well before the planned vacuum fill of the RCS. During this period, it was determined that the threads on the mechanical seal for the Train B reactor vessel level indicating system probe were galled and completion of the head assembly was delayed. Control room operators and outage management were led to believe that this problem could be corrected within a relatively short period of time and the decision was made to maintain the midloop condition and directly enter the vacuum fill procedure when head assembly was complete. Vacuum fill was delayed approximately 14 hours while waiting for the reactor vessel level indicating system probe threads to be repaired. The calculated time to boil in the event of loss of shutdown cooling during this period was 33 minutes. The licensee did not implement a pre-established contingency plan to refill the RCS to 80 inches above the core plate for delays in RCS work.

c. Conclusions

The licensee did not implement a pre-established contingency plan to refill the RCS to 80 inches above the core plate if RCS delays were experienced. A work activity on the reactor vessel head delayed the vacuum fill procedure for 14 hours and unnecessarily increased the time spent in midloop. This condition slightly increased the overall outage risk profile.

O2 Operational Status of Facilities and Equipment

O2.1 Plant Tours and Walkdowns

a. Inspection Scope (71707)

The inspector conducted tours and walkdowns of the following plant areas:

Unit 1 Containment
Unit 1 Containment Sumps
Unit 1 and 2 Auxiliary Buildings
Unit 1 and 2 Electrical Control Building
Unit 1 and 2 Safeguards Buildings
Unit 1 and 2 Control Rooms
Fuel Building

b. Observations and Findings

The inspector accompanied licensee personnel during close-out inspections of the Unit 1 containment building and Unit 1 containment sumps prior to startup from the refueling outage. Both sumps were in good condition and were free of debris that could challenge the operability of the emergency core cooling system pumps. The coarse and fine mesh screens on the trash racks covering both sumps were in good condition and securely in place. The inspector also toured the steam generator compartments, the seal table room, and the 808 foot elevation of the containment building during the final closeout inspection. All areas were in good condition and free of debris. The inspector noted only minor discrepancies which were easily corrected by personnel performing the inspections. Licensee personnel independently performed a thorough inspection.

The remainder of the plant continued to be in good condition. Outage material was controlled to minimize its effect on the safe operation of the facility and combustible material was controlled properly. The licensee used rope boundaries and signs to alert outage personnel about important safety equipment relied upon for the removal of decay heat from Unit 1 during the outage.

During tours of the control room, the inspectors noted that the licensee appropriately logged, entered, and exited Technical Specification (TS) limiting conditions for operation during planned maintenance and surveillance activities. Operability was properly determined prior to exiting the limiting conditions for operation. The inspectors reviewed both the Unit 1 refueling outage and Unit 2 at-power maintenance schedules and found them to properly consider risk and TS requirements. No high-risk combinations of maintenance were identified. Operator turnovers were observed to include sufficient detail of both emergent and planned activities. Oncoming operators were alert and demonstrated a questioning attitude.

Operators conducted surveillance testing in a professional manner. Communications were complete and concise. Repeat-backs were used at all times and both independent and self-verification was evident.

Safety-related tagouts were properly prepared and authorized with only a few minor discrepancies noted. Errors in tagouts were infrequent and promptly identified and corrected by the licensee. Operators properly restored equipment with few exceptions following maintenance. One error occurred in the Unit 1 main generator primary cooling water valve lineup but operators were alert to changing primary water temperature during the startup and quickly tripped the main generator before any damage could occur.

O2.2 Train A Engineered Safeguards Features (ESF) Walkdown

a. Inspection Scope (71707)

The inspectors conducted a walkdown of the risk-significant Unit 1 Train A safety-related equipment prior to and during midloop operations. Specifically, the inspectors toured the Unit 1 Train A emergency diesel generator, residual heat removal, and spent fuel pool cooling systems, including the control boards.

b. Observations and Findings

The inspectors found the rooms containing the Unit 1 Train A ESF equipment properly posted as equipment relied upon for reactor core decay heat removal defense-in-depth plans. The appropriate areas were roped off with descriptive placards limiting access and alerting plant personnel of the need to not conduct any maintenance on the systems within the roped off areas.

The inspectors found the Unit 1 Train A ESF equipment in the proper standby condition. Postmaintenance cleanup activities were found to be effective. Some scaffolding was still installed but it was found to be assembled in a manner which would not affect equipment operability.

c. Conclusions

Important safety-related ESF equipment was found in the appropriate standby condition and roped off in accordance with reactor core decay heat removal defense-in-depth plans.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments (61726, 62707)

In general, maintenance and surveillance activities were characterized by knowledgeable and professional maintenance personnel. Quality and skill of the craft were evident in maintenance activities. Effective communications and planning were evident in both maintenance and surveillance activities. Issues associated with fuel handling during the Unit 1 refueling outage represented potential weaknesses in attention to detail and independent verification.

M1.2 Maintenance and Surveillance Observations

a. Inspection Scope (61726, 62707)

The inspectors observed many Unit 1 maintenance and surveillance activities during the refueling outage, some of which are listed below. More detailed observations are discussed in the following sections:

Unit 1 emergency core cooling system flow balance
Unit 1 Train B diesel generator 24-hour load test
Unit 1 Train B loss of offsite power with safety injection test
Unit 1 Train A diesel generator full load reject test
Unit 1 reactor vessel 10-year inservice inspection
Unit 1 safety-related battery replacement
Unit 1 turbine-driven auxiliary feedwater pump test
Unit 1 steam generator tube eddy current testing
Unit 1 emergency core cooling throttle valve replacements
Unit 1 steam generator atmospheric relief valve modifications
Unit 1 emergency diesel generator maintenance

b. Observations and Findings

Both during the Unit 1 refueling outage and following the Unit 1 startup, the inspectors observed maintenance and surveillance activities selected through a screening of the planned activities based on risk-significance. Important safety-related equipment for which extensive maintenance was planned included the emergency diesel generators, emergency core cooling throttle valves, steam generators, station batteries, and reactor vessel. Maintenance and surveillance activities were generally well conducted.

The Unit 1 reactor vessel 10-year inservice inspection was performed by a contractor using remote controlled cameras and ultrasonic test equipment. The removal of the core barrel from the reactor vessel was an infrequently performed evolution but well controlled. Access to containment was appropriately restricted due to the potential for high radiation levels when a portion of the core barrel was lifted above the refueling cavity water level. The evolution was completed without incident.

The Train B safety injection with loss of offsite power test on Unit 1 was well controlled and good communications were established between the control room and personnel in the field. All equipment performed as expected, with the exception of the safety injection sequencer step counters. These are digital LED [light emitting diode] counters located on the sequencer panel which indicate the elapsed time before each ESF relay actuates. The indicated values on the step counter were included in the acceptance criteria for this test. During the test, sequencer step counter 3 stopped at 10 seconds, as required, indicating that the associated relays for that step had actuated. However, when the sequencer lock-out relay actuated at 99 seconds, step counter 3 jumped to 99 seconds. This was properly noted in the procedure and system operability was evaluated. After reviewing the schematics and other test data, the licensee concluded that this was only an indication problem with and did not affect the operability of any ESF equipment. The actuation times for all ESF equipment were recorded by a data acquisition system used during the test. The inspector reviewed the evaluation and agreed with this conclusion. In addition, the inspector verified that these indications are only used during testing and not by the operators during an actual safety injection actuation.

The diesel generator 24 hour load test required the Unit 1, Train B, diesel generator to be started by an under voltage signal to test the standby feature of the diesel generator as well as the black out sequencer. The test required personnel to time the sequencing of various ESF loads onto the safeguards bus. However, the start of the Train B safety chiller was not accurately timed. In order to correct this, the licensee made a one time procedure change which allowed the test to be performed again, as written, with the start time of the safety chiller being the only required data collection point. This change satisfied the intent of the test and did not pose any equipment preconditioning concerns.

c. Conclusions

Maintenance and surveillance activities were conducted by knowledgeable and meticulous maintenance personnel. Quality and skill were evident in the actual work conducted and little rework was needed. Postmaintenance testing was conducted in a manner which properly verified the system operability and the appropriate data was obtained to monitor system performance.

M1.3 Unit 1 Fuel Handling Errors

a. Inspection Scope (92901)

The inspector reviewed the licensee's investigation and corrective actions regarding two separate fuel handling errors during the Unit 1 refueling outage. The first event involved the mispositioning of a thimble plug in the spent fuel pool while the second event involved reloading the Unit 1 core out of sequence.

b. Observations and Findings

During the Unit 1 refueling outage, contract employees were in the process of moving thimble plugs in the Unit 1 spent fuel pool in preparation for the Unit 1 core reload. This process was performed by three technicians: one to operate the fuel handling tools, one to perform independent verification of the pool locations, and one to act as a procedure reader. During one such move, the fuel handling tool operator correctly latched and removed a thimble plug from pool location N23. The technician reading the procedure told him to place it in location M23 but received no repeat back from the tool operator. The tool operator thought he was told to place the thimble plug in location P23 and did so. There was no independent verification of this step by the third technician. The thimble plug inserted freely into the fuel assembly in location P23 but, when the tool was unlatched and removed, the thimble plug appeared to be only partially inserted and was leaning to one side. At this point, the technicians stopped and informed their supervisor. Further investigation revealed that the plug had been inserted in the wrong location and the fuel assembly in location P23 contained a rod control cluster assembly which had prevented full insertion. The licensee suspended fuel assembly insert movements in the spent fuel pool for 2 days while investigating the causes of this event and formulating corrective actions. When activities were resumed, the thimble plug was retrieved and discarded in the spent fuel pool trash rack. The fuel assembly and rod control cluster assembly in location P23 were inspected and revealed no damage. Failure to properly position the thimble plug in the spent fuel pool in accordance with the fuel shuffle sequence plan was in violation of plant Procedure RFO-106, "Development and Implementation of the Reload Shuffle Sequence Plan."

During the Unit 1 core reload, four fuel assemblies were loaded into the core out of sequence as specified in the fuel shuffle sequence plan. The licensee utilized contract employees as well as licensee personnel in the fuel building, containment, and the control room to coordinate the fuel movements. Personnel in the fuel building determine which assembly is to be sent to containment using the fuel shuffle sequence plan and confirm this information with the control room. Personnel in the fuel building had just completed step 158 in the sequence by transferring the fuel assembly from pool location J26 to containment. There was a short delay before the next sequence step could be completed during which the fuel building personnel became unsure of the pool location for the next assembly to be transferred. They asked the control room if step 159 was next, however, due to poor communications, the control room believed that they had just completed step 159 and instructed fuel building personnel to go to step 160 in the sequence. After step 160 had been completed, three more assemblies were loaded into the core before the error was detected. At this point, core alterations were suspended. Failure to follow the proper core reload sequence in accordance with the fuel shuffle sequence plan was in violation of plant Procedure RFO-106, "Development and Implementation of the Reload Shuffle Sequence Plan."

Following discovery of the reload sequence error, the licensee held a critique to determine the cause and formulate immediate corrective actions. An evaluation was also performed which concluded that there were no reactivity concerns resulting from the error and the initial safety evaluation for the Unit 1, Cycle 8, final core loading plan was still valid for the current core configuration. The root causes of the error were determined to be a lack of self-verification by fuel building personnel, the lack of a questioning attitude by personnel involved, and inadequate communications between the fuel building and the control room. As a result, the licensee performed a complete core map and a partial spent fuel pool map. This confirmed that only four assemblies had been loaded out of sequence. In addition, a reload deviation plan was developed and implemented to restore the proper core reload sequence. Prior to resuming fuel movements, the licensee conducted additional training for refueling personnel and stationed an additional supervisor in the fuel building to monitor communications and verify the pool locations against the fuel shuffle sequence plan.

Technical Specification 5.4.1 requires, in part, that procedures and instructions be implemented in accordance with NRC Regulatory Guide 1.33, "Quality Assurance Program Requirements." Regulatory Guide 1.33, Appendix A, Section 2, requires procedures for general plant operations, including refueling and core alterations. The licensee's station refueling manual, Instruction RFO-106, "Development and Implementation of the Reload Shuffle Sequence Plans," Revision 10, requires fuel assemblies and inserts to be moved as specified by the fuel shuffle sequence plan. Contrary to this requirement, a thimble plug was placed in an incorrect spent fuel pool location and four fuel assemblies were loaded into the core out of sequence. This Severity Level IV violation of TS 5.4.1 is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The incorrect placement of the thimble plug and the core reload sequence error were entered into the licensee's corrective action program as Smart Forms SMF-1999-002717-00 and SMF-1999-002905-00, respectively (NCV 50-445/9916-01).

c. <u>Conclusions</u>

The licensee made two separate errors during fuel handling activities: (1) the positioning of a thimble plug in the incorrect fuel assembly and (2) a sequence error while reloading the Unit 1 core. Both of these errors were attributed to a lack of attention to detail and ineffective independent verification. In both cases, personnel discovered their own errors, suspended activities, and notified their supervisors. The failure to properly implement the fuel shuffle sequence plan in accordance with plant procedures was a violation of TS 5.4.1. This Severity Level IV violation is being treated as a noncited violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. The incorrect placement of the thimble plug and the core reload sequence error were entered into the licensee's corrective action program as SmartForms SMF-1999-002717-00 and SMF-1999-002905-00, respectively.

M8 Miscellaneous Maintenance Issues (92902, 92700)

M8.1 **(Closed) Licensee Event Report (LER) 50-445;446/99-001-00:** RCS power-operated relief valves (PORVs) not properly tested as required by plant TS. On May 10, 1999, the licensee identified that the PORV actuation circuits had not been properly tested as required by TS Surveillance Requirements 4.4.4.1 and 4.4.8.3.1. The missed surveillance was reported in LER 50-445;446/99-001-00 in accordance with 10 CFR 50.73(a)(2)(B). Surveillance procedures were appropriately modified and the untested contacts were tested satisfactorily during the next shutdown. TS 3.4.8.3 required the PORVs to be operable in Modes 4, 5, and 6 for low temperature overpressure protection and TS 3.4.4 required the PORVs to be operable in Modes 1, 2, and 3 for overpressure protection. Due to the location of the untested contacts, the licensee concluded that the PORVs remained operable for Modes 1, 2, and 3 because the untested contact did not preclude manual operation of the relief valves. Although the automatic mode of operation was preferred, there was no TS restriction to rely on manual operation of these valves while in Modes 1, 2, or 3. 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 SmartForm SMF-1999-001289-00 (NCV 50-445;446/9916-02).

M8.2 **(Closed) LER 50-445/97-009-00:** slow opening of Unit 1 east bus supply Breaker 8000 resulted in a turbine and reactor trip. The licensee found that the cause of the slow operation of Breaker 8000 was a bushing installed backwards. The bushing was replaced and installed properly, maintenance procedures were enhanced, and no other instances of improperly installed bushes have since been identified.

M8.3 **(Closed) Violation 50-445/98002-02:** inadequate control of switchyard activities. The licensee chartered a task team to negotiate improved controls over switchyard activities with the Glen Rose transmission organization which maintains the Comanche Peak Steam Electric Station switchyard. The improved switchyard control process increased the control the plant has over activities conducted in the switchyard and integrated the planning of switchyard activities into the plant planning and scheduling organization. The licensee's corrective actions were adequate to control switchyard activities and the inspectors observed properly controlled switchyard activities.

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. Engineering products were of high quality and demonstrated a questioning attitude.

E2 Engineering Support of Facilities and Equipment

E2.1 Pipe Support Failures on the Unit 2 Feed System

a. Inspection Scope (92903)

The inspector reviewed the immediate corrective actions and root cause investigation regarding the failure of three spring can pipe supports on a feedwater heater drain line in Unit 2.

b. Observations and Findings

While making rounds in the Unit 2 turbine building, licensee personnel discovered three failed spring can supports on the drain line for Feedwater Heater 2-4A. This was a 10-inch drain line which drains Feedwater Heater 2-4A to either Feedwater Heater 2-5A via the normal drain valve or directly to the main condenser via an alternate drain valve. Failure of the spring cans left approximately 49 feet of pipe unsupported and allowed it to sag 5 inches until it came in contact with a 1-inch line below it. At the time of the failure, the 10-inch line was experiencing high flow induced vibrations caused by throttling a valve in a 2-inch warmup line connected to the drain line. The licensee took immediate actions to restrict personnel access to that area of the turbine building and effect a temporary repair to support the drain line. The valve in the warm-up line was also shut in order to reduce vibration. A permanent repair was completed the next day by replacing the failed spring cans. The warm-up line which was inducing vibration in the drain line was added during a previous modification on both units in an attempt to reduce water hammer in the feed system during startup. Although the similar valves in the Unit 1 system were throttled almost completely shut and were not inducing a great deal of vibration, the licensee shut these valves as a precautionary measure.

The licensee convened a task team to research the root cause for this event, determine the extent of condition, and make recommendations for corrective actions. The spring cans in question were equipped with a turnbuckle attached to the spring with a threaded rod in order to adjust the tension of the support. The upper threaded rod was tack welded to the turnbuckle by the manufacturer to prevent movement. The threaded rods on all three spring cans failed at the tack weld. Analysis of the threaded rods confirmed that the failure was due to fatigue most likely caused by prolonged vibration. At the end of this inspection period, the task team was still evaluating long-term corrective actions and possible plant modifications to reduce pipe vibration and preclude similar failures in the secondary plant.

c. Conclusions

Three spring can supports on the Unit 2 Feedwater Heater 2-4A drain pipe failed, leaving 49 feet of the 10-inch pipe unsupported. The potential failure of this pipe would have resulted in a minor increase in core damage frequency. Nevertheless, it posed a serious personnel hazard. The licensee's immediate corrective actions were commensurate with this conclusion. Long-term corrective actions were still being evaluated in order to preclude similar failures in other secondary systems.

E2.2 Plant Modifications

a. Inspection Scope (37551)

The inspector reviewed a plant modification to replace the actuators on the Unit 1 steam generator atmospheric relief valves. This included a review of the modification package, safety evaluation, the Final Safety Analysis Report, and partial observations of modification implementation.

b. Observations and Findings

Design Modification 91-177 was developed to replace the Unit 1 steam generator atmospheric relief valve actuators and valve internals in an attempt to provide more precise control of the valves and reduce seat leakage. In the past, this leakage has contributed to valve seat damage. The new valve design had a maximum capacity of 900,000 pound-mass per hour which was approximately equal to the old valve design and was bounded by the steam generator tube rupture analysis. The new valve actuators, like the existing ones, were air actuated; however, they differed in that instrument air was used not only to open the valve but also to close the valve rather than relying solely on a closing spring. This allowed for greater control over the position of the valve. The inspector verified that this was adequately addressed in the safety evaluation and that no new failure modes were introduced with the new actuators since they were also equipped with a spring that would close the valve on loss of air pressure. The safety evaluation also addressed the additional air required to operate the valves and considered it to be bounded by Accumulator Sizing Calculation SC-658841-1. Therefore, no modification to the steam generator atmospheric relief valve accumulators was necessary.

c. Conclusions

The safety evaluation performed for Design Modification 91-177 was clear and concise and adequately addressed design differences in the new steam generator atmospheric relief valve actuators and valve internals. The inspector agreed with the conclusion that the modification did not represent an unreviewed safety question and would improve the operation and maintainability of these valves.

E8 Miscellaneous Engineering Issues (92903, 92700)

E8.1 Completion of Year 2000 (Y2K) Readiness Review

The inspectors reviewed the licensee's implementation of Y2K readiness changes to the plant simulator and the Unit 1 condensate polishing system. These were the only remaining Y2K program items that had not been completed prior to July 1, 1999. No issues were identified by the inspectors.

E8.2 (Closed) LER 50-445/97-002-01: invalid assumptions for containment spray switchover. The licensee's corrective actions associated with the original LER, its aforementioned supplement, and NRC Violation 50-445(446)/9803-04 were reviewed by the inspectors in NRC Inspection Report 50-445(446)/99-14. As such, this closure is administrative and the inspectors conclusions remain valid.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Comments (71750)

During the Unit 1 refueling outage, the inspectors routinely observed radiation workers during maintenance, surveillance, testing, and refueling activities. Reactor coolant system crud burst activities were successful at the beginning of the outage, resulting in low dose rates and reduced radiation worker dose. In addition, the number of personnel contaminations were consistent with past outages with similar work schedules. When questioned, radiation workers were knowledgeable of their radiation work permit requirements.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During routine tours of the facility, the inspectors observed the conduct of security and safeguards activities. The inspectors observed that changing plant security barriers and lighting needs were well controlled during the outage and security officers were alert and attentive to their duties.

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, fire watches were present at all activities associated with welding or grinding and were knowledgeable of their responsibilities, and that the proper precautions were observed during grinding and welding activities to prevent fires.

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 November 15, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

C. L. Terry, Senior Vice President and Principal Nuclear Officer
M. Lucas, Maintenance Manager
D. Moore, Acting President, Nuclear Operations
M. Sunseri, Acting Operations Manager
D. Goodwin, Acting Shift Operations Manager
J. R. Curtis, Radiation Protection Manager
D. L. Walling, Plant Modification Manager
D. Kross, Outage Manager
D. L. Davis, Nuclear Overview 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	Follwoup - Maintenance
IP 92903	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-445/9916-01	NCV	Failure to follow refueling procedures (Section M1.3).
50-445(446)/9916-02	NCV	Reactor coolant system power operated relief valves not properly tested as required by plant Technical Specifications (Section M8.1).

Closed

50-445/9916-01	NCV	Failure to follow refueling procedures (Section M1.3)
50-445(446)/99-001-00	LER	Reactor coolant system power operated relief valves not properly tested as required by plant Technical Specifications (Section M8.1).
50-445(446)/9916-02	NCV	Reactor coolant system power operated relief valves not properly tested as required by plant Technical Specifications (Section M8.1).
50-445/97-009-00	LER	Slow opening of Unit 1 east bus supply Breaker 8000 resulted in a turbine and reactor trip (Section M8.2).
50-445/98002-02	VIO	Inadequate control of switchyard activities (Section M8.3).
50-445/97-002-01	LER	Invalid assumptions for containment spray switchover (Section E8.2)

LIST OF ACRONYMS USED

ESF	engineered safeguards features
LED	light emitting diode
LER	licensee event report
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
PORV	power-operated relief valve
RCS	reactor coolant system
TS	Technical Specifications