ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Reports: 50-445/95-04
50-446/95-04

Licenses: NPF-87
NPF-89

Licensee: TU Electric
ATTN: C. L. Terry, Group Vice President
Nuclear Production
Energy Plaza
1601 Bryan Street, 12th Floor
Dallas, Texas

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: February 12 through March 25, 1995

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
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Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection, including plant status, onsite followup to events, plant operations, maintenance observations, onsite engineering, plant support activities, followup maintenance, and onsite review of an licensee event report (LER).

Results (Units 1 and 2):

- Plant Operations

Performance in the area of operations continued to be very good. Improved control room formality and communications were noted. Licensee management attention was evident. Some minor logging issues were identified that were immediately corrected by operators when so informed. Changes in the process for control of switchyard activities initiated by operations may have contributed to the switchyard event where a bucket truck backed into and caused minor damage to a breaker in the switchyard (Section 3.5). A violation was identified concerning failure to implement a limiting condition for operation action requirement (LCOAR) and compensatory measures for work performed in an emergency borate piping heat trace installation (Section 7).

- Maintenance

Performance in the area of maintenance was mixed. In general, maintenance activities were conducted appropriately and in accordance with procedures. However, several weaknesses were identified throughout the inspection period. The main weakness appeared to stem from a lack of management oversight of contract-related maintenance activities. These weaknesses were manifested in five examples of failure to follow procedures, three of these examples were discussed in Enclosure 3. Other potential weaknesses were identified in the foreign material exclusion process in the fuel pool camera failure and in material accountability practices.

Licensee response to issues raised in the maintenance area was generally good when management was directly involved. For example, when the licensee identified unusual indications during steam generator eddy current testing, the licensee brought in recognized experts, and retested the areas in question using different probes and techniques. Additionally, the licensee's response to identified weaknesses was generally prompt and thorough.

- Engineering

Performance in the area of engineering continued to be excellent.

- Plant Support

Performance in the area of plant support was very good. Exceptions were noted in the area of fire protection when the inspector identified a failure to post a required fire watch (Section 4.1) and two portable fire extinguishers that had been allowed to exceed their required annual inspections by 1-3 years (Section 6.2). Security performance continued to be excellent. Housekeeping over the inspection period was improved and very good. Material condition improved throughout the inspection period due to the licensee's continuing initiative to improve plant appearance by painting enhancements.

Summary of Inspection Findings:

- Violation 445/9504-01 was opened (Sections 4.1 and 7)
- Inspection Followup Item (IFI) 445/9504-02; 446/9504-02 was opened (Section 3.5).
- IFI 445/9504-03 was opened (Section 4.3).
- IFI 445/9502-01 was closed (Section 7).
- LER 446/94-012 was closed (Section 8).

<u>Attachments</u>:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Acronyms

DETAILS

1 PLANT STATUS

Unit 1 began the inspection period in Mode 1 at 100 percent power. The unit began a power reduction on March 3 to begin the fourth refueling outage (Section 3.3). The unit ended the inspection period with the core defueled.

Unit 2 began the inspection period in Mode 1 at 100 percent power. On March 15, control room operators initiated a turbine runback to approximately 75 percent power to stabilize feedwater suction pressure. The low-suction pressure was caused by a condensate transient which was initiated by an offsite feeder breaker fault (Section 2). Unit power was restored and remained at approximately 100 percent throughout the rest of the inspection period.

2 ONSITE FOLLOWUP TO EVENTS (93702)

Offsite Power Distribution Switchyard Breaker Fault

At approximately 3:13 p.m. CST on March 15, an internal phase to ground fault in the 345 kV Parker line switchyard breaker (8040) developed when the breaker was opened by the control room and caused a loss of the switchyard east bus. The loss of the east bus initiated an isolation of the condensate polishing system, which resulted in a lowering of feedwater pump suction pressure, and required operator intervention to prevent a reactor trip. The inspector responded to the Unit 2 control room.

When the inspector arrived at the control room, the licensee had stabilized the unit at approximately 75 percent power and was in the process of inspecting down secondary plant components to determine whether the plant had sustained damage due to water-induced transients. The inspector verified that the plant was stable and in a safe condition.

The licensee conducted a walkdown of the plant following the transient and discovered that a steam leak had developed in the bonnet of a check valve in the steam extraction line to the Feedwater Heater 2B. Additionally, the licensee secured heater drain Pump 2-02 following its restart when the inboard motor bearing temperature rapidly rose to over 240°F.

The event began when control room operators tried to open the Parker line switchyard breaker. Glen Rose transmission personnel had requested that the control room open the breaker so that maintenance technicians could inspect the breaker. Approximately 54 seconds later, a phase-to-phase bus imbalance caused a bus lockout which opened all feeder breakers on the east bus.

The licensee's evaluation concluded that a voltage transient, induced by the loss of the east bus, caused a perturbation in the condensate polishing system. Soon after the bus lockout, computer parameters indicated a high differential pressure across the demineralizer vessels. The demineralizer vessel outlet valves may have shut in response to a voltage transient seen by the controlling computer. The licensee reported that prior to the trip, the bus voltage dropped to 0.5 percent of nominal for approximately three cycles.

The transient in the condensate polishing system was followed by a rapid drop in feedwater pump suction pressure. The lowering suction pressure may have been the result of the transition from full flow through the condensate polishing vessels to full flow through the bypass valve. Because of the suction pressure drop, the control room operators appropriately tripped heater drain Pump 2-02 to induce a turbine runback. The unit supervisor indicated to the inspector that the suction pressure transient could have potentially tripped the feedwater pumps and ultimately cause a reactor trip. The unit run back to approximately 75 percent stabilized feedwater suction pressures.

The inspector discussed the cause of the breaker fault with the system engineers. The system engineers informed the inspector that the Breaker 8040 was an inverse time element design that has wooden operator arms that operate the breaker contacts. Apparently, the Phase A operator arm broke and either failed to open the Phase A contacts or, allowed the contacts to reclose. A direct short across the phase to ground developed followed by a bus lockout. The inspector viewed the inside of the Phase A breaker and observed that the corrective maintenance had removed all traces of the phase to ground short and that the breaker enclosure was intact.

The inspector observed that the licensee had replaced the wooden operating arms with fiberglass rods. The inspector reviewed the licensee's list of switchyard breakers to determine which breakers still had wooden manipulator arms. Of the twelve 345 kV switchyard breakers, eight were inverse time element breakers. Of these eight, five (including 8040) had been modified with the fiberglass operating arms. The operating arms of the other three breakers were to be replaced at the next scheduled overhaul of the breaker. The licensee informed the inspector that the breaker had operated 33 times since the last overhaul.

The inspector discussed the licensee's action plan with the system engineering manager and with the balance-of-plant system engineering supervisor. The inspector determined that the licensee had already instituted changes to the computer system to increase the sampling frequency on certain condensate polishing system parameters and to add computer points to monitor parameters such as condensate polishing bypass and demineralizer outlet valve positions. These parameters would help the licensee determine the cause of the secondary transients. Additionally, the system engineering manager stated that they were reviewing whether an uninterruptible power supply for the condensate polishing system computer could prevent the disruption caused by the voltage transient.

The inspector concluded that the control room operators initial response to the transient demonstrated that the operators had an excellent understanding of integrated plant operations. The inspector concluded that, had the licensee not initiated the runback, one or both feedwater pumps were susceptible to a low suction pressure trip which could have ultimately resulted in a reactor trip. The inspector also concluded that the licensee's planned actions to investigate the power supply and to expand the computer monitoring capabilities were appropriate. Finally, the inspector concluded that the failure of the wooden operator arms did not represent a significant problem and that licensee plans for replacement were appropriate.

3 PLANT OPERATIONS (71707)

The inspectors conducted daily examinations of control room staffing, control room access, adherence to procedures, compliance with Technical Specifications (TS) and operator behavior and attentiveness. Selective examinations of engineered safety features, electrical, and emergency core cooling system lineups using control room indications were performed to ensure safety system availability. The status of control room annunciators was reviewed and operators were questioned on their knowledge of alarmed annunciators. In addition, the inspectors verified that appropriate investigative and/or corrective action had been initiated. Logs for shift operations, clearances, and for limiting conditions for operation were reviewed for accuracy and corrective action. Reactor coolant system leak rate determinations were reviewed. Shift turnovers and pre-evolutionary briefs were periodically observed.

Tours of accessible areas within the plant were conducted to evaluate general plant cleanliness, material and equipment condition, and potential personnel and equipment hazards. Plan of the day, plant scheduling, and other meetings were attended to ascertain overall plant status and observe licensee management involvement in plant activities. The inspectors independently performed walkdowns of selected portions of engineered safety feature systems to verify proper valve and electrical lineups, identify leakage, verify proper lubrication, confirm cooling water availability, and to identify any other condition which could have prevented the fulfillment of the systems' required function.

Selected safety-related clearances were reviewed to determine if they were properly prepared and implemented. The inspectors performed periodic reviews of the problem identification (ONE Form) documents and associated corrective actions to verify that the process was functioning properly and to identify any trends in plant performance.

3.1 Plant Tours

The inspector observed general plant housekeeping improve during this report period. The licensee continued to paint and perform upkeep of plant spaces and equipment. Plant workers typically removed waste and tools from work sites with few exceptions. Licensee management appropriately ensured that temporary outage-related equipment was stored properly and that no personnel hazards arose from housekeeping issues. Emergency core cooling valve rooms continued to pose a challenge to plant housekeeping with numerous leaks and inconvenient radiological conditions for plant workers. Storage of temporary plant equipment such as ladders and gas storage bottles were typically in accordance with plant procedures, and, when found unproperly stored the licensee immediately corrected the observation.

3.2 Control Room Observations

The inspector observed licensee efforts to facilitate improved outage management by providing additional personnel in the control room and communication expectations. Control room formality and communications improved. Alarming annunciators were quickly responded to and announced. Pre-evolutionary briefs were more frequent and appropriately formal and complete, particularly for sensitive evolutions. Management involvement in control room operations was apparent. Control room logs were thorough and typically maintained consistently from shift to shift with few exceptions.

3.3 Unit 1 Power Reduction to 1RF04

The inspector observed portions of the power reduction, reactor shutdown, and plant cooldown activities for 1RF04. The power reduction commenced on March 3, in accordance with Procedure IPO-003A, Revision 9, "Power Operations."

Plant parameters were appropriately monitored by the operators per licensee management expectations. Operators exhibited a questioning attitude and attention to detail throughout the power reduction. Overall, the inspector observed very good communications between control room operators and maintenance workers. The unit supervisor maintained excellent control of the unit and provided good oversight of operator actions. Formal repeat backs between the unit supervisor and the operators were evident. The control room was sufficiently staffed with the required number of licensed operators. The inspector noted that additional operations personnel were stationed in the control room to support 1RF04. Reactor engineering provided excellent support to operations for establishing projected boric acid and reactor makeup water additions to control temperature and predicted ramp rates in order to maintain Delta I on target. Control room logs were generally very good. However, the inspector noted a couple of instances where Technical Specification entries were not correctly logged. Operators immediately corrected the logs when the inspector informed them of the discrepancies.

3.4 1RF04 Meetings

The inspector attended various outage-related meetings throughout the inspection period, which included coordinator's meetings, outage planning meetings, and meetings associated with cessation of work after numerous issues were identified by both the licensee and the NRC. Overall, the inspector noted that open communications existed between the outage group and the individual work groups and that the meetings were very effective in communicating management's expectations.

The outage group acknowledged questions that were raised during the planning meetings and incorporated them into the work schedule. The inspector concluded that planning meetings were well conducted with appropriate management involvement.

The inspector attended work cessation meetings for mechanical maintenance and radiation protection. The inspector observed that the cognizant managers thoroughly discussed the lessons learned from issues identified during 1RF04 and, appropriately, reinforced management expectations.

3.5 Control of Vehicles in Switchyard

On March 19, TU Electric transmission personnel, performing insulator maintenance on Breakers 8000 and 8010 located in the switchyard, inadvertently backed a bucket truck into the fiberglass cover on Breaker 8070 (345 kV Benbrook breaker). The impact caused minor damage to the truck and the fiberglass cover. Approximately 4 hours after the impact, the control room was notified by plant security. Once notified, the shift manager assessed the damage to Breaker 8040 concluding that the damage did not affect operability and wrote ONE Form 95-290. The licensee classified the issue as a plant incident.

The inspector toured the switchyard with the electrical maintenance manager on March 23. It was apparent that little room existed for maneuvering a truck in the vicinity of Breaker 8040. The inspector questioned the licensee on their practice for controlling work in the switchyard, particularly as it related to the movement of large trucks in the vicinity of high voltage. The licensee indicated that it was both a site and TU Electric Company practice to have a person available to direct the movement of large vehicles in the vicinity of high voltage devices. The licensee indicated that no person was directing movement of the vehicle which backed into the Breaker 8040.

The inspector reviewed the licensee's control for access to the switchyard and found, as did the licensee, that a recent revision to their switchyard control practices in January 1995 may have contributed to the event. The licensee had established switchyard and control practices in response to their July 1990 review of NUREG-1410, "Loss of Vital AC Power and the Residual Heat Removal System During Mid-Loop Operations at Vogtle Unit 1 on March 20, 1990." Prior to January 1995, keys for access to the switchyard had to first be obtained from security. Workers requesting access to the switchyard were required to brief the control room on the details concerning the work to be performed prior to security issuing keys.

In January 1995, the licensee convened a switchyard task team headed by the operations department to evaluate issues surrounding the Unit 1 turbine trip of December 2, 1994. One issue identified by the licensee's switchyard task team involved the ability of TU Electric transmission personnel to gain quick access to the switchyard. In response to the issue of timely acquisition of keys for the TU Electric transmission organization, the licensee issued switchyard keys to the Glen Rose transmission group. The Glen Rose transmission group was still required to obtain permission from the control room prior to entering the switchyard. However, the licensee found that, transmission personnel often obtained permission from the control room by calling from the relay house inside the switchyard itself. As interim measures to control switchyard activities, the licensee took control of switchyard keys and escorted workers into the switchyard.

As part of the resolution of the plant incident, licensee procedures require a formal root cause determination and develop corrective actions. The inspector will continue to follow licensee actions (IFI 445/9504-02; 446/9504-02).

4 MAINTENANCE OBSERVATIONS (62703)

During this inspection period, the inspectors observed selected maintenance activities for structures, systems, and components (SSCs) listed below to verify that the maintenance activities were conducted in a manner that resulted in reliable safe operation of the plant and plant equipment. Inspectors performed observations, conducted reviews, and interviewed maintenance personnel to verify that maintenance activities were performed in compliance with regulatory requirements.

The inspectors evaluated the effectiveness of maintenance by verifying that the licensee properly tested and calibrated equipment using appropriate procedures that ensured postmaintenance operability of SSCs. Other aspects evaluated included the effectiveness of equipment history and a maintenance record review by the licensee intended to identify repetitive failures or other adverse trends, which could indicate ineffective or inadequate maintenance. In addition, maintenance procedures were reviewed to ensure the appropriate quality control or independent verification hold points existed to ensure that critical work steps were performed adequately.

Inspectors verified that the appropriate approvals were obtained, the appropriate safety tagout boundaries were established before initiating work, and that operation impact reviews were appropriately requested. The inspectors evaluated the effectiveness of communications between maintenance workers and other interface organizations during observations of maintenance activities. Radiological work practices and controls were assessed. Control of plant risk and compliance with TSs were evaluated.

The following maintenance activities were observed.

- Corrective maintenance to replace Check Valve 1CS-8443 in the chemical and volume control system (CVCS) in accordance with Work Order (WO) 3-94-305179-01.

- Preventive maintenance to hydrolaze the Unit 1 Train B component cooling water (CCW) heat exchanger.

- Corrective maintenance performed on Unit 1 as directed by WOs 1-94-064784-00 and 1-94-070649-00 for ultrasonic testing on CCW Check Valves 0690 and 0697.

- Preventive maintenance performed on the Unit 2 main steam safety valves as directed by WO 5-93-502702-AA.

- Corrective maintenance performed on Unit 1 as directed by WO 1-94-067036-00 on CCW isolation valve, 1CC-0666.

- Design modification implemented on Unit 1 containment spray Pump 1-01 as directed by WO 2-95-081142-00 to replace the four-vane impeller with a five-vane impeller to reduce the amount of vibration on the containment spray pump and piping system.

Selected observations from review of the above maintenance-related activities are discussed below.

4.1 Unit 1 - Corrective Maintenance on CVCS Check Valve 1CS-8443

On March 21, the inspector observed portions of the replacement of the boric acid to CVCS Boric Acid Blender 1-01 check valve, 1CS-8443 in accordance with WO 3-94-305179-01 in Room 203. The inspector observed mechanical maintenance contractors tack weld the new check valve in place in preparation for welding the root pass.

The inspector noted that the fire permit required the removal of all combustible material below and within 35 feet of the area, or that the material be protected by a fire retardant barrier; that a nonplant fire extinguisher was at the work location; and that a fire watch was provided. The inspector noted the welder tack welding the check valve had no fire watch stationed at the work location and that unprotected combustible materials were within 35 feet of the welding activity contrary to the fire permit. This material included various rags, paper, a catch containment located within inches of the welding activity, and anticontamination clothing, none of which were covered with fire retardant material. In addition, the inspector noted that the portable fire extinguisher for the activity was located outside of the room (outside of the contaminated area) where the welding was being performed.

Plant Procedure STA-729, "Control of Transient Combustibles, Ignition Sources and Fire Watches," Section 6.4.1.1, states, that a fire watch shall be established when a fire permit is issued. Section 6.3 states that an CPSES fire permit (FP) is required when an ignition source is to be used. The inspector concluded that the welder was using an ignition source to perform tack welds and was required to have a fire watch in accordance with procedure.

The inspector questioned the workers about the posted Housekeeping Zone II requirements for the activity, which required the workers to log all of the items and personnel that enter and exit the Zone II area on a personnel and material/tool accountability log. The inspector noted that the contract workers maintained a list of the items that were brought within the Housekeeping Zone II area on the back of a scrap of paper; however, this list did not indicate whether the item had been removed from the area nor assign accountability of the item to an individual. The inspector noted that a quality control inspector was present to verify the cleanliness of the system being welded. In addition, the mechanical maintenance contract supervisor for this activity was not present, and was unaware of the conditions that existed until informed by the inspector.

The inspector informed the mechanical maintenance manager of the findings. The mechanical maintenance manager stopped all welding activities to reemphasize management expectations associated with welding.

The inspector noted that quality control did not identify any problems or concerns with activities being performed in Room 203. The inspector noted that logging the material accountability on a scrap of paper as opposed to the personnel and material/tool accountability sheet was a poor practice even if the intent was to transfer the information later. Also, the materials that were listed on the scrap of paper for the maintenance activity did not include an exit verification of the items, did not assign accountability to an individual, and did not include the personnel within the Housekeeping Zone II area. The inspector noted that supervisory oversight of the mechanical maintenance contractors, who performed the welding activity was not evident. The inspector concluded that the failure to have a fire watch present during welding activities was an example of a violation of CPSES procedural requirements (Violation 445/9504-01).

4.2 Confined Space Entry

During a plant tour of Unit 1, the inspector observed contract workers for mechanical maintenance and construction operations support group cleaning a small space beneath the Train B emergency diesel generator. The inspector questioned the workers whether they were in a confined space. The workers indicated that it was not a confined space. Subsequently, at the inspector's request, a safety services representative viewed the area and concluded that the space did constitute a confined space based on the potential work restrictions, accessibility problems, and potential engulfment hazards. The licensee indicated that they would revise the "Confined Space Entry" procedure (STA-628) to incorporate this area into a listing of confined spaces in the plant. In addition, the licensee indicated that they would use lessons learned in future confined space entry training courses. Specifically, training would emphasize and inform workers on management's expectations for evaluation of what constituted a confined space. The inspector concluded that the decision to perform work in a confined space without a confined space permit was a potentially unsafe work practice from a personnel safety standpoint.

4.3 Unit 1 - Steam Generator U-Tube Damaged by Sludge Lance Tool

On March 19, a high pressure sludge lance tool came loose from its bayonet mount and was ejected by high pressure water into the base of one steam generator (SG) U-tube. The licensee performed eddy current testing on the tubes surrounding the missile's trajectory and found only one tube with significant damage indications. The licensee plugged the damaged tube and initiated an investigation surrounding the event.

On March 18, a contractor (Westinghouse Corporation) performed sludge lancing on the secondary side of SG 1-03. Following completion of sludge lancing, the operators noted that the sludge lance tool was missing a flat bar that was part of the tool's locking mechanism. The licensee/contractor performed a foreign object search and retrieval and recovered the flat bar but was unable to locate the small retaining screw.

Next, the contractor reinstalled the flat bar with a new screw and began to sludge lance SG 1-02. Following completion, the operators again noted that the screw and flat bar had come loose but had not fallen off. Technicians removed the bar to prevent it from falling off and again falling into a SG and because the technicians thought that they were finished with the lancing evolution.

While performing the sludge lancing on SG 1-02, an inspection of SG 1-03 revealed some sludge which had not been removed. The contractor intended to try to remove the remaining sludge after completion of SG 1-02. Following a crew shift change, the contractor moved the sludge lancing equipment back to SG 1-03 to remove the remaining sludge. When the technician inserted the sludge lance nozzle into the generator, he noticed that the flat bar was missing and informed the night shift supervisor. Without contacting licensee management, the contractor supervisor decided that the machined flat area on the nozzle was sufficient to prevent disengagement of the nozzle and that they would proceed without the bar. The inspector considers this removal of the locking mechanism to be an unauthorized modification of the sludge lancing device.

While performing a flush in the T-slot area of SG 1-03, the nozzle disengaged from the positioning rod and was ejected by 2000 psig water into the base of one of the U-tubes. The licensee inspected all the tubes two rows deep that surround the T-slot and discovered that only the tube at the end of the T-slot showed significant damage. The tube was subsequently plugged. Because the nozzle was being positioned manually in this area, the licensee believed that the lock tab may have been accidently depressed which allowed the nozzle to rotate.

The inspector reviewed the incident with the contractor's outage manager and examined the design of the nozzle. The inspector noted that the sludge lance nozzle was attached to the positioning rod with a bayonet-type mount. The nozzle was inserted and then turned 90 degrees. The nozzle locked into place when a small, spring-loaded tab extended into an opening in a flat bar attached to the nozzle. The flat bar was attached to the nozzle by a single cap screw approximately 1/8-inch long. To disengage the nozzle, the spring-loaded tab was depressed into the positioning rod and the nozzle was rotated 90 degrees in either direction. The flat bar both locked the nozzle by preventing rotation, and prevents the tab from being accidentally depressed.

The inspector also noted that the sludge lance nozzle consisted of two sets of four nozzles which sprayed perpendicular to the positioning rod. The reaction forces from the two sets of nozzles opposed each other and, therefore, did not develop a lateral force. However, the lines of force from the two sets of nozzles were offset by approximately 1 inch which would cause a torque to develop during operation. Without the locking device, the inspector concluded that the torque could potentially rotate the nozzle to the point where it could disengage. At 2000 psig water pressure, the sludge lance could cause significant damage should it disengage from the positioning rod.

The inspector reviewed the two ONE forms related to the sludge lance failure. The first was submitted on March 19, after the sludge lance had impacted into the SG tube, and the second was submitted March 20 to evaluate the missing screw that was lost on March 18. The inspector concluded that the licensee had two prior opportunities to prevent the sludge lance failure. The first, following the initial loss of the lock bar and screw in SG 1-03. And the second, following the technician's identification that the screw had again started to come loose following sludge lancing in SG 1-02.

The inspector noted the licensee was conducting an investigation of the events surrounding the sludge lance failure. The inspector will review the licensee's findings and the corrective actions. The inspector will also review the licensee's oversight of the contractor's activities and the adequacy of the contractor's procedures (IFI 445/9504-03).

4.4 Unit 1 Main Steam Safety Valve Testing

On March 4, 1995, the inspector witnessed mechanical maintenance workers perform portions of the Unit 1 main steam safety valve (MSSV) testing in accordance with WO 5-93-502702-AA. The WO directed mechanical maintenance to verify the set pressure of MSSV, 1-MS-0130 for SG 1-04 in accordance with the "Main Steam Safety Valve Testing" procedure (MSM-SO-8702, Revision 2). The inspector observed the test from the control room and locally at the MSSVs.

The licensee originally planned on testing 4 of the 20 MSSVs. However, the first test of Valve 1MS-0130 indicated that the valve's set pressure (1180.46 psig) was outside of the pressure range acceptance criteria. Mechanical maintenance informed the control room of the failed test, which caused 1MS-0130 to be inoperable. Maintenance personnel adjusted the valve's setpoint in accordance with Procedure MSM-SO-8702. The second test of Valve 1MS-0130 also failed with an indicated set pressure of 1183.1 psig. Again, mechanical maintenance adjusted the set point of Valve 1MS-0130. The subsequent retest indicated that the set pressure was acceptable. Since the initial test of Valve 1MS-0130 failed its pressure test, two additional valves were tested in accordance with Part 1 of ASME/ANSI OM-1987, which states that two additional MSSVs shall be pressure tested for each valve failure. Of the four MSSVs originally tested, only Valve 1MS-0130 failed so two additional valves were required to be tested. The remaining two MSSVs tested were within the acceptance criteria.

During the testing, the inspector verified that the pressure gauges used for the test were within their calibration frequency. Mechanical maintenance conducted the test in accordance with procedure. The inspector observed that system engineering and mechanical maintenance support were present during portions of the testing and for the retesting of the failed MSSV. Quality control appropriately reperformed the calculations for setpoint pressures, using the pneumatic assist method, which incorporates the local main steam line pressure and the air motor pressure that causes the MSSV to lift.

Later, the inspector reviewed the control room logs and found that TS 3.7.1.1 was not entered and exited in the control room logs when Valve 1MS-0130 failed its set pressure test. The action statement requires that with one or more main steam line code safety valves inoperable, that within 4 hours, either the inoperable valve is restored to operable status or the power range neutron flux high trip setpoint is reduced; otherwise, be in at least hot standby within the next 6 hours and in hot shutdown within the following 6 hours. The licensee stated that the control room operators recognized that they were in an TS action requirement but failed to log the entry into the log. The inspector found that Valve 1MS-0130 was returned to operable status within 2 hours of the failed test. Therefore, the action statement would have been met. The inspector concluded that the failure to administratively log that TS 3.7.1.1 was entered and exited was a departure from typical control room log keeping practices.

4.5 Unit 1 - SG U-Tube Inspections

During the forth refueling outage of Unit 1, the licensee performed routine eddy current testing on the U-tubes in SG 1-02 and 1-03. As planned, the licensee performed eddy current tests using a rotating pancake coil (RPC) probe for the first time. These tests were conducted between the tube end and the first support plate. The licensee tested 100 percent of the tubes that had been expanded using the Wextex explosive expansion process and a sampling of the rolled tubes for a total in both generators of approximately 1200 tubes.

The licensee identified approximately 100 tubes which had indications that were initially classified as axial anomalies. The licensee called in two industry experts; one, a contractor for Westinghouse, and the other from Electric Power Research Institute, to help resolve the indications. The experts determined that the anomalies were not true defect indications; however, they recommended additional testing because some of these anomalies may have been masking some other type of potential defect. These new indications were all in the tube sheet transition region. None of these indications were readily apparent using bobbin coil probes.

The licensee selected a sample of 27 tubes which were initially classified as having axial anomalies, 13 in one SG and 14 in the other, and performed additional eddy current inspections using a RPC probe called a plus point. The new probe was a spherical probe and was designed to provide resolution of volumetric defects. The experts concluded that the axial anomalies were not true defects. They also concluded that 13 or 14 tubes had some indications which required further investigation. They believed that the data may indicate that the tubes had circumferential defects on the inner diameter of the tube which extended between 180 to 270 degrees.

The licensee conducted additional tests using a combined ultrasonic and RPC probe in an attempt to further clarify the indications. Because the probes had to be placed into the tube manually, the licensee selected only the four tubes that had the strongest indications for additional testing in the tube transition area using the ultrasonic probe. After obtaining ultrasonic test data from the first two tubes, the licensee determined that the tubes did not have circumferential defects.

The inspector reviewed a sample of the original data showing the axial anomaly. The inspector noted that the terrain plots of the data did show some unusual indications; however, the plots did not have typical indications of axial defects. The inspector also noted that the locations which may have shown circumferential indications were not definitive. The inspector concluded that performing additional inspections was appropriate. The inspector provided the licensee's printouts to a region-based inspector for further analysis. The region-based inspector did not have any immediate concerns on the integrity of the tubes.

4.6 Reactor Vessel Head Removal

The inspector performed an audit of Procedure MSM-CO-9901, "Reactor Vessel Head Removal and Installation," that was performed on the initial Unit 1 reactor vessel head removal. In addition, the inspector viewed a videotape of the head removal that was captured from the newly established video cameras located in containment. Procedure MSM-CO-9901 provides instructions to lift the reactor vessel head 12 to 24 inches above the vessel flange and hold it for 10 minutes while visual inspections are performed and requires a witness to initial that the inspection was performed. However, the inspector identified that the verification initial was not transferred onto the final work package. The inspector questioned Westinghouse whether or not the step was witnessed. Subsequently, Westinghouse transferred the original initial that was located on a working copy of the procedure in containment to the final work package. The inspector concluded that it was apparent from the videotape of the head removal that the hold point in the procedure was performed, and that the process of transferring an initial for verification of a hold point and visual inspection of the reactor vessel head was not timely.

5 ONSITE ENGINEERING (37551)

The inspectors performed a limited assessment of the licensee's design and engineering processes to determine the root cause of problems and evaluate the adequacy of engineering support to plant operations. A selected review of licensee design control, plant modification design and installation, and engineering and technical support to plant operations was conducted. Configuration management was evaluated to ensure the plant's physical and functional characteristics were maintained in conformance with the plant's design and licensing bases. ONE Forms were reviewed daily to assess engineering involvement in determining the root cause of problems, and evaluate the adequacy of engineering support in dispositioning operability issues. Engineering involvement in maintenance and surveillance activities was reviewed to determine if adequate support was evident.

Selected observations from the reviews conducted are discussed below.

5.1 Unit 2 - N32 Source Range Detector

The inspector reviewed ONE Form 95-157 regarding a control board walkdown that was performed on Unit 2, in which a Bistable Light 2-TSLB-6, Window 2.1, "SR Flux Hi NC-32D," was found lighted. Upon further investigation, the licensee found that the N-32 source range detector was energized and the count rate was at its maximum value. The operators entered the applicable Abnormal Procedure ABN-701, Revision 5, "Source Range Instrument Malfunction," which instructed them to place the affected source range level trip switch in block, and remove the instrument power fuses to deenergize the detector. Licensee troubleshooting revealed that the high voltage cutout circuit board, CB103, was intermittently failing, which caused the high voltage to turn on the source range detector at full power. System engineering determined that the source range detector appeared to be operable, since output was observed the entire duration of its energized state. The operability of the source range detector will be determined the next time the unit enters Mode 3. Operations personnel established a limiting condition for operation for tracking purposes.

The inspector concluded that the operators appropriately entered the applicable procedure when it was discovered that the abnormal condition existed. However, the inspector was concerned that it took operators 5 hours from the time the computer alarmed to discover that the condition existed. The inspector questioned operations management, who indicated that certain control board parameters were viewed when the computer alarm came in; however, verification of the exact location of the startup rate counter indicator was not performed. Operations management reinforced their expectation to operators for verifying the exact location of control room indicators (i.e., pegged high or low). The inspector concluded that this appeared to be an isolated example of inattentiveness of operations personnel.

5.2 Unit 1 - Alternate Power Supply Diesel Temporary Modification

The inspector reviewed the licensee's design modification for the installation of three alternate power diesel generators (APDGs). The licensee installed the temporary diesels as an enhancement to shutdown risk. The installation consisted of routing permanent Nonclass 1E cables and conduits from the existing Class 1E 6.9 kV emergency busses to a transfer switch located outside the Unit 1 safeguards building. Temporary cables were used to connect the transfer switch to three portable diesel generators. The inspector reviewed the design modification to ensure that the Nonclass 1E installation did not compromise the Class 1E emergency busses.

The inspector reviewed the design modification (DM 94-037 Revision 0) with design engineers. The inspector noted that the cables and conduits were classified as associated Class 1E. The design engineers explained that the associated components were built and installed to the same specifications as Class 1E components. However, the cables were connected to the transfer switch and did not have train separation at this location. Additionally, the breakers would be connected to Class 1E busses through the spare breakers in the Class 1E cabinets.

The inspector reviewed the licensee's plan to ensure the independence of the Class 1E components from Nonclass 1E components. The inspector noted that the installation was only intended for an emergency. Specifically, the installation was intended to be used in Modes 5 and 6 only to provide power to either (but not both) Class 1E 6.9 kV bus in the event of a failure of both Class 1E emergency diesel generators coincident with a loss of offsite power. The licensee planned to control the independence of the Class 1E components by keeping both spare breakers in the racked out position unless the emergency situation described above were to occur. Additionally, the licensee intended to ensure that the breakers remained in the racked out position using the licensee's locked component control procedure (ODA-403).

The inspector observed selected portions of the installation and testing of the APDGs. The inspector noted that the design engineers and maintenance management and supervision was present and involved with the evolution.

The inspector considered that the installation of the APDGs demonstrated licensee management's effort to enhance the reliability of electrical power supplies during outage situations and added another layer to the defense in depth strategy. Additionally, the inspector concluded that the design modification was appropriately evaluated to ensure the independence of the Class 1E components from Nonclass 1E components. Finally, the inspector noted excellent engineering and management involvement during the installation and testing of the APDGs.

6 PLANT SUPPORT ACTIVITIES (71750)

The inspector performed routine inspections to evaluate and verify that licensee performance of radiological controls, fire protection, physical security, and emergency preparedness activities were conducted in conformance with licensee procedures and regulatory requirements.

6.1 Radiation Protection

During plant tours, the inspectors verified the use of locks to control access to radiological controlled areas (RCAs) and reviewed selected surveys to check their consistency with postings within the surveyed areas. The inspectors found that surveys appropriately reflected plant conditions and that locks to RCAs were utilized properly and in accordance with procedural requirements. Licensee activities within the RCA were observed and the inspectors verified and ensured that personnel followed appropriate radiation worker practices.

The inspector witnessed portions of the reactor coolant system crud burst during the Unit 1 shutdown. Chemistry followed the procedural requirements appropriately to induce the crud burst by adding hydrogen peroxide to the CVCS. An auxiliary operator manipulated the valves in order to execute the chemical addition for the crud burst in accordance with procedure. S [illegible] verification and checking techniques were utilized. Later, chemistr[illegible] samples to identify the amount of hydrogen peroxide that was induced [illegible] the system. However, initial indications showed that the necessary amounts of hydrogen peroxide to induce an acceptable crud burst were not accomplished. Overall, chemistry made five hydrogen peroxide additions to induce an adequate crud burst. The coordination between operations and radiation protection (RP) was very good. The inspector noted that RP technicians and the RP supervisor were present near rooms that were expected to receive high radiation doses due to the crud burst. RP implemented as-low-as-reasonably-achievable practices by preventing personnel from entering rooms that had expected changing radiological conditions. RP support to plant operations, maintenance, and surveillances was very good.

6.2 Fire Protection - Portable Fire Extinguishers

During the maintenance activity discussed in Section 4.1, the inspector examined the portable fire extinguisher that was designated for the hot work activity. The inspector found that the annual inspection was last performed in August 1993. The inspector informed the mechanical maintenance contract supervisor for the activity, who subsequently replaced the extinguisher. Licensee management instructed workers to collect all portable fire extinguishers in the RCA that had exceeded their required annual inspection as evidenced by the inspection tag and to return them to the tool crib for reinspection. The workers indicated that they found one portable fire extinguisher in the plant that exceeded its annual inspection requirement. Two days later, the inspector performed a general tour of the RCA and found another portable fire extinguisher that exceeded its annual inspection. The extinguisher inspection tag was dated December 1991, and appeared to be designated for a welding or grinding activity associated with RHR Train B work. Again, the inspector informed maintenance personnel, who later removed the portable fire extinguisher from the work location. Maintenance personnel indicated that the work activity had been completed.

The inspector questioned FP personnel about the control of portable fire extinguishers. FP indicated that fire extinguishers that are used for hot work activities, such as welding and grinding are issued from the respective tool rooms. The tool room attendant checks the pressure gauge on each extinguisher and ensures the needle is in the green area which indicates charged, checks that the pull pin and tamper seal are in place, and determines if any damage or corrosion exists prior to issuing the extinguisher. However, the inspection tags are not required to be verified. The fire extinguisher noted by the inspector appeared to be in good physical condition and the attached guage indicated that it was fully charged. FP personnel are responsible for ensuring that the extinguishers are maintained. Also, FP stated that a recent quality assurance audit performed noted concerns as to where the portable fire extinguishers were issued. As a result of the inspector's findings and the quality assurance audit, FP plans to incorporate a computerized system in the tool room to maintain control of the portable fire extinguishers, which will include the dates for the annual inspections.

6.3 Security

Inspection of the licensee's physical security activities included verification of the general integrity of the protected area barriers, maintenance of the isolation zones around these barriers, and protected area personnel access areas. The inspector found that the integrity of all barriers were excellent. The inspector noted that security verified that appropriate lighting on temporary equipment placed in the protected area was adequate.

7 FOLLOWUP-MAINTENANCE (92902)

(Closed) IFI 445/9502-01: Emergency Borate Heat Tracing Issue

While performing a plant tour on February 7, the inspector discovered approximately seven feet of emergency borate system piping missing insulation downstream of Valve 1-8104 in the Unit 1 CVCS room. The inspector observed that although the heat tracing (Circuit 16) was energized, it was loosely draped over the pipe with no tape holding it in place, and the heat trace junction boxes were left open. The inspector questioned the licensee about the nature of work which was apparently being performed, and inquired what compensatory measures were being taken to assure the pipe temperature remained high enough to maintain the 7000 ppm boron in solution. The licensee found that no LCOAR was initiated and that no compensatory measures had been implemented. The unit supervisor immediately verified that the temperature of the pipe was above 65°F as required by plant TS, had not dropped below 65°

since November 1994, and appropriately initiated compensatory measures to ensure the room temperature remained above 65°F. ONE Form 95-113 was initiated.

The licensee's initial investigation into One Form 95-113 revealed that WO 1-94-073961-00 was opened in August 1994, to troubleshoot and correct heat trace issues identified during preventive maintenance. A review of WO 1-94-073961-00 showed that Unit 1 heat trace Circuits 1, 2, 16, 30, 32 33, 34, 35, 36, and 43 failed a current test performed during preventive maintenance under WO 3-94-318740-01 in early August 1994. Circuits 1, 2, 4, 16, 30, 32, and 33 were TS related and, appropriately, the work package required entry into a LCOAR. During troubleshooting efforts in August 1994, the licensee initiated compensatory measures to monitor boration flowpath temperature. However, once troubleshooting was completed and the degraded heat trace circuits identified, compensatory measures required by tracking LCOAR T3-94-121 were stopped on August 27, 1994. Nevertheless, the WO remained open for repairs to the degraded circuits. Due to Unit 2 outage workload and manpower restrictions, work on the degraded heat trace was delayed. In December 1994, work restarted on the degraded heat trace circuits. The work involved coordination between the maintenance services and electrical maintenance departments to de-energize the affected circuits, remove insulation, replace defective heat tracing, and reinstall the insulation. However, an LCOAR and compensatory measures were not implemented for work on Circuit 16 from December 13, 1994, through February 7, 1995, as required by licensee Procedure ODA-308, Revision 5, "LCO [Limiting Condition for Operation] Tracking Program."

Section 6.4.2 of ODA-308, states, in part, that an active LCOAR or an inprogress LCOAR shall be initiated and that the unit supervisor shall ensure compensatory measures are being taken when it is determined that an WO, clearance, etc., impacts the operability of any system which is TS related. Corrective maintenance WO 1-94-073961-00 specified that an LCOAR and an impact review be performed prior to initiation of work. The compensatory measures which should have been implemented and were implemented initially in August 1994, included monitoring the affected boration flowpath temperatures.

The licensees investigation revealed a number of factors and implemented corrective actions related to the heat trace issues as follows:

(1) LCOAR release practices and auxiliary operator expectations - management reemphasized auxiliary operator expectations and operations received a procedure deficiency for closing the tracking LCOAR with the WO still open;

(2) the WO should have been rescheduled rather than allowing the maintenance department treat the work as discretionary - work control issued "lessons learned;"

(3) electrical maintenance should have had the WO reimpacted by operations and reported the resumption of work to the control room - electrical

maintenance received a procedural deficiency for not having the WO reimpacted when work was started more than 3 weeks after authorization and not notifying the control room prior to the resumption of LCOAR related work;

(4) heat trace procedures should identify which circuits are TS related - electrical planning and maintenance initiated improvements to heat trace procedures;

(5) scope of work package should have been limited to TS heat trace circuits - TS related heat trace repairs now require individual work packages;

(6) scheduling of heat trace and freeze protection should consider outage impact and weather - systems engineering is pursuing the separation of heat trace and freeze protection programs scope such that inspections are more program specific and do not overlap;

(7) system engineer periodic reviews and system status expectations - review management expectations and use issue as a "lesson learned;" and

(8) coordination of work between electrical maintenance and maintenance services - implement improvements in coordination of heat trace work.

The inspector concluded that the licensee's corrective actions associated with Circuit 16 were appropriate and thorough. However, when the inspector questioned the licensee about their review of other TS related heat trace circuits associated with WO 1-94-073961-00, the inspector found that they had not considered the other circuits in their review. The licensee immediately verified that the other circuits were operable. The inspector concluded that the licensee's failure to implement an LCOAR as required by the WO was a violation of licensee procedures (Violation 445/9504-01).

8 ONSITE REVIEW OF AN LER (92700)

(Closed) LER 446/94-012: Manual Reactor Trip and Auxiliary Feedwater Autostart Due to SG Lo-Lo Level Signal

The inspector reviewed LER 94-012 pertaining to a Unit 2 manual reactor trip from 75 percent reactor power on August 15, 1994. Unit 2 was in the process of being shut down due to an oil leak on the high voltage phase bushing for Main Transformer 2MT2. Licensee management decided to have the unit manually tripped to deenergize the main transformer in order to prevent damage to the bushing and/or the transformer. Reactor Coolant Pump 2-01 tripped due to an electrical transient caused by the unit trip. Repeated auxiliary feedwater pump auto-start engineered safety feature initiation signals occurred due to SG lo-lo level signals. Investigation by the licensee determined that the oil leak was the result of cracking/failure of the bushing housing on 2MT2. Corrective actions included sending the failed bushing assembly to the vendor for analysis. The engineered safety feature actuation occurred as a normal result of the SG level shrink from the reactor trip following the closure of the turbine stop valves. However, the repeated engineered safety feature initiation signals occurred due to a failed control card in the steam dump control circuit, which was later replaced. The inspector concluded that the licensee's investigation and subsequent corrective actions were found to be appropriate.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. D. Bird, Jr.	Nuclear Planning Manager
M. R. Blevins	Assistant to Vice President of Nuclear Operations
D. L. Davis	Maintenance Overview Manager
E. L. Dyas	Nuclear Specialist, Nuclear Operations
R. T. Jenkins	Electrical Maintenance Manager
J. J. Kelley	Vice President, Nuclear Engineering/Support
D. C. Kross	Operations Support Manager
J. J. LaMarca	Unit 1 Outage Manager
B. T. Lancaster	Plant Support Manager
M. L. Lucas	Maintenance Manager
F. W. Madden	Engineering Overview Manager
D. M. McAfee	Programs Overview Manager
N. C. Paleologos	Vice President, Nuclear Operations
R. J. Prince	Radiation Protection Manager
C. W. Rickgauer	Maintenance Overview Manager
S. L. Smith	Work Control Manager
B. R. Snellgrove	Mechanical Quality Control Supervisor
D. W. Snow	Senior Regulatory Compliance Engineer
G. J. Stein	Mechanical Maintenance Manager
C. L. Terry	Group Vice President, Nuclear Production
R. D. Walker	Regulatory Affairs Manager

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

1.2 NRC Personnel

A. T. Gody, Jr., Senior Resident Inspector
V. L. Ordaz, Resident Inspector
H. A. Freeman, Resident Inspector

2 EXIT MEETING

An exit meet ng was conducted on March 29, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

ACRONYMS

APDG	alternate power diesel generator
CCW	component cooling water
CVCS	chemical volume and control system
FP	fire protection
IFI	inspection followup item
LCOAR	limiting condition for operation action requirement
MSSV	main steam safety valve
NFPA	National Fire Protection Association
ONE Form	problem identification process
PDR	public document room
RCA	radiologically controlled area
RP	radiation protection
RPC	rotating pancake coil
SG	steam generator
SSC	system, structures, and components
TS	Technical Specifications
WO	work order