ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/95-13
50-446/95-13

Licenses: NPF-87
NPF-89

Licensee: TU Electric
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: June 12 through July 20, 1995

Inspectors: Linda J. Smith, Reactor Inspector, Engineering Branch
Division of Reactor Safety

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Approved: Elmo E Collins 7/30/95
Elmo E. Collins, Acting Chief, Engineering Branch Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1 and 2): Nonroutine, announced inspection in response to the failure of the Unit 1 turbine-driven auxiliary feedwater pump to operate on demand and subsequent followup inspection related to the mechanical overspeed trip of the Unit 2 turbine-driven auxiliary feedwater pump during testing.

Results (Units 1 and 2):

Engineering

- The licensee preliminarily determined that governor valve stem corrosion was the most probable cause of the June 11, 1995, Unit 1 turbine-driven auxiliary feedwater pump mechanical overspeed trip. The licensee also identified as other possible contributing causes water in the steam lines and air in the governor hydraulic control circuit (Section 3.1).

- The licensee preliminarily determined that excessive condensate buildup was the most probable cause of the June 21, 1995, Unit 2 mechanical overspeed trip. However, subsequent to this inspection internal damage was discovered in the governor valve stem packing assembly which could also be a contributing cause (Section 3.2).

- The licensee had not aggressively or comprehensively addressed condensate in the turbine-driven auxiliary feedwater system. Licensee personnel did not question that water frequently sprayed from the turbine casing sentinel valves during turbine startup (Section 2.3).

- Licensee personnel did not consider the turbine-driven auxiliary feedwater system drains to have a safety-related function. Consequently, licensee personnel had not demonstrated if the nonsafety-related drains and steam traps failed, that condensate accumulation was adequately controlled to achieve satisfactory operation of the turbine. The capability to control condensate in the auxiliary feedwater pump turbine steam supply and exhaust to assure safe and reliable turbine operation is an unresolved item (Sections 2.3, 4.7, 5.3, 6.1, and 6.2).

- The priority for repairing leaking steam admission valves was not consistent with the design basis of the system condensate drain capability (Section 5.3) and exacerbated the rate of governor valve stem corrosion (Section 6.1).

- The licensee's review of industry events did not alert them to the importance of assuring the operability of auxiliary feedwater steam traps, drains and exhaust (Section 6.2).

Management Overview

- The licensee's aggressive investigation of flow noises in the Unit 2 auxiliary feedwater system resulted in the discovery of significant system degradations (Section 3.2).

- Regulatory requirements related to work order implementation were not appropriately included in Station Administrative Procedure STA-606, "Work Requests and Work Orders," Revision 22. The procedure repeatedly used the word "should," which indicated a management expectation that could be changed with supervisory concurrence, in lieu of "shall," to communicate regulatory requirements to site personnel. This is one example of a violation of NRC requirements (Section 7.3).

Plant Operations

- Due to operator inattention, the Unit 1 auxiliary feedwater pump turbine was operated prior to completion of prerequisite valve alignments and maintenance checks. This is one example of a violation of NRC requirements (Section 7.1).

- The operator authorized a performance verification test of the Unit 2 safety-related auxiliary feedwater turbine which had not been appropriately reviewed and approved. He also incorrectly determined that a step to lower the speed controller to 0 percent during a warmup run was not applicable. This is one example of a violation of NRC requirements (Section 7.2).

Summary of Inspection Findings:

- Violation 445/9513-01; 446/9513-01 was opened (Section 7).
- Unresolved Item 445/9513-02; 446/9513-02 was opened (Sections 2.3, 4.7, 5.3, 6.1, and 6.2)

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 TURBINE-DRIVEN AUXILIARY FEEDWATER SYSTEM DESIGN (37550, 93702)

1.1 System Description

Each unit has a turbine-driven auxiliary feedwater pump which is capable of feeding each of four steam generators. The turbine is supplied steam from two of the main steam lines, loops one and four.

For each turbine, air-operated steam supply Valves HV-2452-1 and -2 open upon system initiation to provide steam to the turbine. Each steam supply valve has a bypass valve, Valves MS-0711 and -0712, respectively. The bypass lines are used for warming the steam lines during some maintenance and test activities. The bypass valves remain closed during emergency operation.

The steam supply valves and the bypass valves are located near the top of the auxiliary building. Turbine trip and throttle Valve HV-2452 is located near the turbine, approximately 100 feet below the steam supply valves. Separate steam supply piping is routed from each steam supply valve to the trip and throttle valve through approximately 500 feet of steam supply piping. Due to high energy line break concerns, the system is designed so that the steam supply piping is cold. This results in significant condensate formation during a cold automatic system start. The turbine casing is provided with a small pressure relief valve (sentinel valve) which opens and whistles to alert personnel on high turbine exhaust pressure.

The trip and throttle valve is normally open and only closes for a turbine trip. The governor valve is used to control turbine speed and during standby, the turbine governor valve is normally open. Upon system initiation, the steam supply valves open, the turbine accelerates, and the governor valve begins to close. The turbine continues to accelerate until the governor valve closes to reduce turbine speed to minimum, about 2200 RPM. At this point, the governor valve will ramp open until turbine speed matches the lower of the turbine speed settings on the local controller or the control panel. During standby, both turbine speed controllers are set at 100 percent.

The steam supply lines are 4-inch, ASME Section III Code, Class 3 piping. The steam supply is provided with a drain pot and drain piping which connects to a turbine low pressure drain line and is routed to a floor drain. A steam trap is installed between the drain pot and the floor drain. The drain pot and orifices from the steam supply line are ASME Section III Code, Class 3. The steam trap is classified as nonsafety.

Drain lines from the turbine exhaust and the trip and throttle valve run through a nonsafety low-pressure steam trap and connect to the high-pressure steam line drains before entering the floor drain. Additional nonsafety turbine shaft seal and turbine casing drains are routed to the same floor drain. In Unit 1, the drains are hard piped to the floor drain. In Unit 2, the point where the drain lines enter the floor drain is insulated so that steam will not enter the room.

1.2 Design Bases

Final Safety Analysis Report, Section 10.4.9.1, "Design Bases," states that the auxiliary feedwater system provides feedwater as a cooling source during a feedwater line break. Final Safety Analysis Report, Section 15.2.8.2, accident analyses for a feedwater line break, assumes that one motor-driven auxiliary feedwater pump fails, one motor-driven auxiliary feedwater pumps supplies water to the break, and that flow from the turbine-driven pump is needed 85 seconds after the low-low steam generator water level initiation signal. Section 10.4.9.1 also states that the system operates over the full operating pressure range of the steam generators.

The preoperational tests required to demonstrate the capability and reliability of the auxiliary feedwater system are described in Table 14.2-2, Sheet 51. They include: demonstration that the turbine-driven pump is capable of delivering flow within acceptable time limits; five quick cold starts; and, a 48-hour endurance run followed by a cool down and subsequent restart.

2 EVENT DESCRIPTIONS

2.1 Unit 1 - Failure of Turbine-Driven Auxiliary Feedwater Pump On Demand

On June 11, 1995, a manual reactor trip was initiated following a loss of both main feedwater pumps during testing. Water level fell rapidly in Steam Generators 1-01 and 1-02 and initiated an automatic start of the turbine-driven auxiliary feedwater pump. The turbine-driven auxiliary feedwater pump started and accelerated; however, the governor valve failed to control the acceleration and the pump tripped on overspeed. An operator in the room reported water spraying from the turbine sentinel valve. The licensee declared the pump inoperable at 12:03 p.m. and did not attempt to restart the pump. NRC Inspection Report 50-445/95-11; 50-446/95-11 documented review of the event.

2.2 Unit 2 - Turbine-Driven Auxiliary Feedwater Pump Overspeed During Testing

During quarterly testing on June 16, 1995, the licensee heard an unusual noise at the pump. The licensee preliminarily classified this noise as cavitation and terminated the test. The licensee later determined that the noise was from the flow restricting orifice and not cavitation. The licensee observed a large amount of water coming out of the turbine exhaust. A second test was performed later that day and the pump performed satisfactorily with no unusual noise.

A test was performed on June 21, 1995, to further investigate the cause of the unusual noise and confirm that the pump was not cavitating. The licensee prewarmed the steam supply pipe by opening the two steam bypass valves. The operators did not set the speed controller to zero as was normally done. See Section 7.2 for a description of associated test control issues.

Opening the bypass valves provided enough steam to roll the turbine to about 3500 revolutions per minute during the warmup run. The system engineer noted that the governor valve was operating in a jerky motion. After approximately 4 minutes, the bypass valves were closed.

Thirteen minutes later, the turbine was started by opening the steam admission valves. The turbine tripped on overspeed. The control room noted a speed of about 5000 revolutions per minute. The licensee observed that the governor valve stem did not move and water was leaking out of the stem packing. The sentinel valve on the turbine casing opened and the licensee observed that water was spraying out of this valve for the duration of the event. The licensee also observed a significant amount of water coming out of the exhaust pipe. The licensee declared the turbine-driven auxiliary feedwater system inoperable.

An hour after the trip, the licensee found by ultrasonic testing that condensate had collected in the steam supply piping. About 8 hours after the trip, the licensee opened the steam supply drain line and approximately 5 gallons of water flowed from the line.

2.3 Units 1 and 2 - Water Spray from Turbine Sentinel Valves During Some Turbine Runs

The inspectors noted that water spraying from the turbine casing sentinel valve was common to both events and could be an indicator of inadequate condensate control. Also, as a result of interviews with plant personnel, the inspectors determined that significant amounts of water sprayed from the turbine sentinel valves during some turbine startups.

The inspectors questioned if there was any impact of this condensate on turbine operation. The licensee did not view the condensate from the sentinel valve as a significant problem for the following reasons. Condensate formation and removal in the steam supply piping had previously been evaluated during startup testing. Extensive modification and testing activities were performed at that time to ensure that the condensate which formed during a cold start would not prevent the turbine from fulfilling its safety function. In addition, neither auxiliary feedwater pump turbine had failed a quarterly cold-start test since the beginning of commercial operation.

The inspectors considered that the licensee had become focused primarily on the steam supply condensate formation and consequently did not question the amount of water at the sentinel valves or the turbine exhaust. This focus may also have contributed to the untimely identification of a steam trap design installation error (Section 4.6) and degraded steam traps (Section 3.2). The capability to drain condensate in the turbine-driven auxiliary feedwater pump steam supply, turbine casing, and turbine exhaust to assure safe and reliable system operation is an unresolved item (445/9513-02; 446/9513-02).

3 PRELIMINARY CAUSE DETERMINATION AND INITIAL CORRECTIVE ACTION

The licensee had not completed their formal root-cause analysis at the end of this inspection. The inspectors reviewed the licensee's investigation, preliminary-cause determination, and the associated corrective actions.

3.1 Unit 1

The licensee preliminarily determined that the Unit 1 failure-on-demand was caused by a corroded governor valve stem. The inspectors observed that the governor valve stem corrosion was visibly similar to corrosion seen at other facilities which had experienced governor valve stem binding. This binding had been attributed to stem corrosion after a change in governor valve stem material from gas-nitrided Type 410 stainless steel to liquid-nitrided Type 410 stainless steel.

Premature corrosion of governor valve stems was the subject of NRC Information Notice 94-66, "Overspeed of Turbine-Driven Pumps Caused by Governor Valve Stem Binding." The licensee was aware of the corrosion issue and replaced the governor valve stem during Refueling Outage 1RF-04. The replacement governor valve stem had only been in service 8 weeks prior to the June 11, 1995, failure.

After the overspeed trip, the licensee replaced the corroded valve stem with a stem manufactured from Inconel 718. The licensee planned to do metallurgical testing of the removed stems to determine the exact composition of the stem materials. The licensee also planned to inspect the condition of the Inconel 718 stems monthly.

The licensee planned additional monitoring to ensure that condensate buildup or air in the governor valve control hydraulic circuit had not been contributing causes. The licensee also committed to a full evaluation of the drain system including the steam lines upstream of the steam admission valves and potential horizontal runs of the steam lines.

Industry experience suggested that another possible cause of an overspeed trip was uncontrolled modifications to the governor related to subcontract procurement interfaces. The licensee contacted the turbine vendor and determined that the governors were correctly configured.

3.2 Unit 2

The licensee initially determined that the off-normal warmup run configuration caused an excessive build-up of condensate, which resulted in the overspeed trip. The vendor stated that a large amount of water could interfere with the governor valve's ability to close and result in an overspeed trip. The licensee found that one of the steam traps was not operating and the other steam trap was degraded. The licensee repaired the steam traps. The inspectors concluded that the licensee's aggressive investigation of flow noises resulted in discovery of the steam trap degradations described in Section 5.1 and the incorrect steam trap insulation design described in Section 4.6.

Steam admission valve leakage was also determined to be a contributor to excessive condensate accumulation. While the licensee determined that steam leakage through the steam admission valves did not cause the event, little or no leakage from the valves might have mitigated the event. The licensee planned to rework the steam admission valves to correct the leakage. The valves did not have specific leakage requirements. This issue is discussed further in Section 5.2.

The licensee also inspected, cleaned, and adjusted the governor valve linkage.

The licensee tested the pump (warm) on June 22, 1995, to verify the performance of the governor valve. The licensee closed the normally open trip and throttle valve and opened the steam bypass valves to prewarm the pipe. The trip and throttle valve was slowly opened admitting steam to the turbine. The licensee observed that the governor valve moved smoothly as the turbine speed was increased. The licensee then closed the steam bypass valves and opened the steam admission valves. The trip and throttle valve was slowly opened admitting steam. The licensee observed that the governor valve operated smoothly as the turbine speed increased.

The licensee performed additional tests on June 23, 1995, to verify that the turbine would restart under hot conditions. The licensee closed the trip and throttle valve and opened the steam bypass valves. The trip and throttle valve was slowly opened to admit steam to the turbine. The licensee noted that the governor valve operated smoothly as the turbine speed increased. The turbine was run at 4000 revolutions per minute and then shut down. The licensee repeated the test by opening the steam admission valves and slowly opening the trip and throttle valve. The licensee determined that the governor valve was operating properly. Again the turbine was shut down. Thirteen minutes later, the steam admission valves were opened and the turbine ramped to rated speed. The inspectors considered that this testing demonstrated that the turbine was capable of a hot restart with functioning steam traps.

On June 24, 1995, the licensee performed a cold-start test. The turbine was ramped to its rated speed of 4075 revolutions per minute. The system was declared operable at 9:04 a.m. on June 24, 1995, based on the successful cold-start test.

The Unit 2 governor valve stem was replaced with an Inconel 718 stem on July 21, 1995. During that stem replacement the licensee discovered a worn valve stem bushing and broken carbon spacer, which may also have contributed to the Unit 2 overspeed trip. See NRC Inspection Report 50-445/95-14; 50-446/95-14 for a review of this issue.

4 DESIGN AND TESTING REVIEW

4.1 Units 1 and 2 - Condensate Removal Calculations

The inspectors reviewed Unit 1 Calculation 16345-ME(B)-210, Revision 1, "Verification of Orifice Sizing for CP1-MSOROR-05 & 44." The purpose of the calculation was to verify that the main steam drain line orifices would pass the condensate formed in the steam supply line to the turbine at a rate greater than it was formed after the system was in operation and the steam lines were warm. The calculation did not address condensate formation during emergency operation and the calculation was classified as nonsafety-related. The inspectors reviewed Unit 2 Calculation 2-ME-0235, "Verification of Orifice Sizing for CP2-MSORDR-05 & 44," Revision 0. This calculation compared all of the assumptions in the Unit 1 calculation and determined that the results of the Unit 1 calculation were applicable to Unit 2.

Inspectors found that the above calculations only addressed steam supply orifice and steam trap drain capability. Since the licensee did not consider condensate drain capability to be a safety-related function, no calculation(s) existed to establish condensate drain capability in standby or cold quick-start conditions. Also, the turbine casing drains and turbine exhaust drains were not considered. The inspectors concluded that the licensee had not evaluated condensate formation and drainage rates for all design basis steam enthalpies and system operating modes.

4.2 Unit 2 - Slope of Steam Lines

The inspectors reviewed the Unit 2 isometric drawings of the steam lines from the main steam line to the turbine trip and throttle valve. The inspectors found that the isometric drawings showed the piping was sloped to avoid condensate buildup in the steam supply line.

4.3 Steam Traps and Drain Line Modifications

The inspectors reviewed Design Change Authorization 86317, Revision 8 which installed a steam trap in the high pressure steam drain line and a steam trap in the low pressure turbine exhaust drain line of the Unit 1 auxiliary feedwater turbine.

The design basis portion of the design change package stated if the traps failed to open, there would be no effect on the performance of the turbine. The licensee based this assumption on the results of Unit 1 System Functional Test Report 1CP-PT-37-03, Revision 0, which was performed prior to the installation of the nonsafety-steam traps. During this test, the high pressure steam line drain was valved closed. The inspectors considered that the system functional test demonstrated that the trap on the high pressure steam side was not necessary (assuming zero steam admission valve leakage).

The inspectors noted that failure of the low pressure traps or the turbine casing drains was not tested. This was of concern since failure of these drains combined with leaking steam admission valves could disable the system due to condensate buildup. The licensee had not evaluated the consequences of these failures. The inspectors concluded that the licensee had not demonstrated, by testing, that the nonsafety-grade turbine casing drains and the drain line on the turbine exhaust line were unnecessary.

The inspectors reviewed Unit 2 System Functional Test Report 2CP-PT-37-03, Revision 0. All of the drain lines were left open during the test. Therefore, the inspectors concluded that Unit 2 test had not demonstrated that the system could operate without the nonsafety-related steam traps and drain lines.

The inspectors also noted that a steam exhaust drain was not installed in Unit 2 at the bottom of the exhaust stack. The inspectors concluded that Unit 2 was apparently more vulnerable to the accumulation of condensate in the turbine exhaust.

4.4 High/Low Pressure Drain Interface

A vendor recommendation, which was included for information in Design Change Authorization 86317, stated that the governor valve stem leak off, the near and far side turbine shaft seals and the trip and throttle valve low pressure leakoff must go to atmospheric pressure or below. In conflict with the recommendation, the governor valve stem leak-off and the trip and throttle valve low pressure leakoff were piped to the turbine exhaust. This design change authorization also routed the output of the high-pressure steam trap, the low-pressure steam trap, and the turbine casing drains through a common manifold to a sealed floor drain. The design change authorization did not include analysis to support the acceptability of this high/low pressure drain interface. The licensee committed to evaluate this issue.

4.5 Units 1 and 2 - Removal of Condensate Level Alarms

Design Change Notice 4082, dated May 7, 1992, disabled the level switches associated with the high condensate level alarm in the turbine high-pressure drain line. The deletion was justified based on successful hot functional tests performed with the high-pressure steam trap isolated. This alarm would have alerted the licensee to the steam trap malfunction in Unit 2.

The licensee approved Design Change Notice 9473 to reestablish the control room high condensate level alarms on July 1, 1995.

4.6 Units 1 and 2 - Steam Trap Lagging Removal

During this inspection, the licensee identified that the installation of the high- and low-pressure steam traps on both turbines was in conflict with vendor recommendations. Vendor Manual 665-02047-002, "Plenty Velan Steam Traps," indicated that insulation removal is required for proper functioning of the steam traps. The manual stated that the trap and at least the last 2-3 feet of the cooling leg should not be insulated, otherwise the trap performance will be affected. The steam traps were not insulated but the cooling leg was insulated. The licensee removed the insulation on Unit 2 prior to declaring the turbine operable on June 24, 1995.

The licensee did not similarly remcve the insulation on Unit 1 until questioned by the inspectors. The Unit 1 lagging was removed on June 29, 1995. The licensee did not believe that installation or removal of the lagging adversely affected operability. The licensee stated that the steam traps do not operate under design conditions and are maintained essentially in standby condition for the purpose of removing water after a turbine run. They concluded that operability was not affected by having the insulation installed.

The inspectors concluded that the licensee was not rigorous in evaluating the relationship between leaking steam admission valves and functioning steam traps. The inspectors considered that the incorrect insulation installation could have contributed to the amount of condensate which accumulated during testing and was observed spraying from the turbine sentinel valves during some turbine runs. The additional insulation would slow the response of a steam trap to accumulated condensate; and result in slower opening of the steam trap.

The inspectors noted during the inspection that the licensee implemented minor modifications to approve the removal of the 4 feet of lagging on all of the cooling legs.

4.7 Conclusions

The inspectors concluded that condensate formation and removal in the steam supply and exhaust system for the turbine-driven auxiliary feedwater pump was not fully evaluated by calculation or test to assure that the design bases requirements would be met. Specifically:

- The calculation for condensate removal and formation was not comprehensive in that it did not consider the condensate drain capability necessary to accommodate leaking steam admission valves.

- The design upper limit for the condensate formation rate did not include an allowance for the condensate created in the turbine casing and in the turbine exhaust system during turbine operation assuming worst-case inlet steam conditions.

- The Unit 1 low-pressure drains, high-pressure drains, and turbine-casing drains were plumbed together and then directed to the floor without analyzing the high/low pressure interface effects on the ability of the lines to drain.

- The licensee did not demonstrate by test or calculation the capability of the turbine-driven auxiliary feedwater pump to meet its design basis requirements if the nonsafety-related low-pressure steam traps and the nonsafety-related turbine casing drains failed.

- The steam trap installations were not designed in accordance with the vendor's recommendation to not insulate the last 2-3 feet of the cooling leg.

These concerns will be evaluated as a part of Unresolved Item 445/9513-02; 446/9513-02.

5 MAINTENANCE REVIEW

5.1 Units 1 and 2 - Steam Trap and Drain Maintenance

After the Unit 2 trip, the licensee disassembled the two steam traps. The trap on the high-pressure steam side was found to be functional, but degraded. It contained a dry powdery rust substance in the trap interior. The top layer of the bimetallic strips were found to be bent at different angles than the lower strips. The licensee stated that the bimetallic strips affected how the stem and plug moved with temperature changes, which could have affected the performance of the trap. The turbine-exhaust drain line trap was found to be full of water and the strainer was clogged. The licensee indicated that the strainer had probably not been working for quite a while. The bimetallic strips were found to be set improperly. The licensee replaced the internals in the traps.

The inspectors noted that the frequency of preventive maintenance activities for the steam traps was every 5 years. Since the licensee considered that the turbine would function even if the steam traps failed, they did not initially specify any preventive maintenance requirements for the steam traps. As a good practice, the system engineer established a 5-year frequency to be consistent with the turbine inspections. The turbine inspections were planned to be performed every third refueling outage. The licensee had inspected the two steam traps on the Unit 1 turbine-driven auxiliary feedwater pump steam drains in May 1995, and the traps were found to be functioning and in good condition. The licensee had not performed the preventive maintenance activities on the Unit 2 steam traps at the time of the overspeed trip because the unit had not been in service for 5 years.

The inspectors considered that the system engineer's actions were appropriate, considering that the turbine would function even if the steam traps failed. However, the inspectors were concerned that classifying the system condensate drain functions as nonsafety-related resulted in a less rigorous preventive maintenance program than might otherwise have been established. As a result of this event, the licensee stated that the preventive maintenance program was under evaluation.

The inspectors noted that prior to the overspeed events, inspections were not planned for the turbine casing drains. Following the overspeed events, the licensee inspected the turbine casing drains in both units and found that they were functioning.

5.2 Leaking Steam Admission Valves

During interviews, licensee personnel stated that both the Unit 1 and Unit 2 steam admission valves were leaking. The Unit 1 leakage was believed to be less significant and to have started after the recent refueling outage. The licensee had previously attempted to repair Valve 2-HV-2452-1 during Refueling Outage 2RF01. The valve was determined to be still leaking on December 31, 1994.

On June 29, 1995, the licensee measured the condensate from the leaking valves. The licensee determined that the Unit 1 leakage was 3.5 gallons per hour and the Unit 2 leakage rate was 18.2 gallons per hour. The inspectors concluded that the Unit 2 leakage rate was significant and combined with the blocked and degraded nonsafety-related steam traps could have been a significant factor in causing the turbine overspeed trip. Approximately 20 gallons of condensate would be enough to fill the turbine to the level of the governor valve and interfere with the auto-start capability of the turbine.

The licensee repaired the Unit 2 steam admission valve (Valve 2-HV-2452-1), which was leaking the most significantly, on July 20, 1995. They also planned to repair the Unit 1 and the Unit 2 steam admission valves, which were still leaking. Valve 1-HV-2452-2 was scheduled for rework the week of August 28, 1995. Valve 2-HV-2452-2 was scheduled for rework the week of August 21, 1995.

The licensee stated that they did not have a limit on the amount of steam admission valve leakage. The system engineer noted that it was his practice to initiate a work request to correct leakage when the leakage was significant enough to cause elevated temperatures at the trip and throttle valve. The inspectors noted that a control room annunciator would alarm if steam admission valve leakage was sufficient to roll the turbine at 5 revolutions per minute.

The inspectors noted that the licensee implemented short-term compensatory measures to monitor steam trap performance which addressed short-term operability concerns.

5.3 Conclusions

The inspectors concluded that the priority for repairing leaking steam admission valves was not consistent with the classification of the condensate drain function as nonsafety-related. The inspectors further concluded that the established steam trap maintenance practices had not ensured adequate condensate removal capability. Further, the licensee defeated the high condensate level alarm which would have alerted them to malfunctioning steam traps. This concern will be evaluated as a part of Unresolved Item 445/9513-02; 446/9513-02.

6 EXPERIENCE REVIEW

The inspectors reviewed the licensee's evaluations of the following NRC generic communications to determine the effectiveness of the experience review program for this issue:

- NRC Information Notice 86-14,"PWR Auxiliary Feedwater Pump Turbine Control Problems," Supplement 1,"Overspeed Trips of AFW, HPCI and RCIC Turbines," and Supplement 2, "Overspeed Trips of AFW, HPCI and RCIC Turbines."

- NRC Information Notice 88-09, "Reduced Reliability of Steam-Driven Auxiliary Feedwater Pumps Caused By Instability of Woodward PG-PL Type Governors."

- NRC Information Notice 93-51, "Repetitive Tripping of Turbine-Driven Auxiliary Feedwater Pumps."

- NUREG 1275 Volume 10, "Operating Experience Feedback Report - Reliability of Safety Related Steam Turbine -Driven Standby Pumps," and

- NRC Information Notice 94-66, "Overspeed of Turbine-Driven Pumps Caused by Governor Valve Stem Binding."

6.1 Experience Review Related to Leaking Steam Admission Valves

In NRC Information Notices 86-14 and 88-09 steam admission valve leakage problems were associated with leakage sufficient to prematurely roll the turbine (based on the assumption that the drains worked). The licensee adequately evaluated the described problem. There was a control room indicator which would alarm if the steam admission valve leakage caused the turbine to roll at greater than 5 revolutions per minute.

The inspectors were concerned that the licensee's review of Information Notice 94-66 did not address the fact that admission valve leakage exacerbated governor valve stem corrosion for susceptible materials. The licensee had noted that corrosion could happen with the susceptible material in less than a month; however, the licensee relied on quarterly monitoring for steam admission valve leaking. The inspectors were concerned that quarterly monitoring was not sufficient to prevent this degradation. This concern will be evaluated as a part of Unresolved Item 445/9513-02; 446/9513-02.

6.2 Experience Review Related to Degraded Steam Traps, Drains, and Turbine Exhaust Lines

NRC Information Notices 86-14 and 88-09 identified problems with excessive condensate formation in the steam supply piping. The licensee recognized that they had this problem. The long runs of cold piping (approximately 500 feet) between the steam admission valves and the trip and throttle valve were expected to form condensate during a cold start. Prior to licensing, the licensee resloped these lines to assure proper drainage and made the necessary control logic changes so that the turbine would reliably start in cold conditions, assuming all other equipment was functioning.

NRC Information Notice 86-14 discussed the importance of routinely verifying the operability of steam drains and traps. NRC Information Notice 86-14 identified that systems had malfunctioned because the overall system dynamic problems were not fully considered. The licensee's evaluation of the Notice considered only the steam supply piping and drain modifications (assuming everything functioned as designed). The licensee did not evaluate the turbine casing and turbine exhaust drains and no action was taken to routinely verify the operability of steam drains and traps.

The licensee continued to maintain this narrow perspective during the review of NRC Information Notice 93-51. The NRC issued Information Notice 93-51 to re-emphasize the importance of a functioning steam trap and drain system. The NRC noted that one utility had removed their steam traps to provide for reliable drainage and had separated the turbine casing drains from other high pressure leakoffs. Licensee personnel, however, did not address either the degraded steam trap issue or the high/low pressure interface drain issue.

As a good practice, during the review of NRC Information Notice 93-51, licensee personnel obtained a copy of the related inspection report for review. The licensee considered, but did not adequately address: inoperable or degraded steam traps, excessive steam admission valve leakage, and potential clogging of the turbine exhaust drains.

The inspectors were concerned that the licensee's review of industry events did not alert them to the importance of assuring the operability of steam traps, drains, and turbine exhaust. This concern will be evaluated as a part of Unresolved Item 445/9513-02; 446/9513-02.

6.3 Corrective Measures

The licensee planned to re-review the relevant industry experience documents. The licensee also planned to join the Terry Turbine User's Group to improve their knowledge of current issues related to Terry Turbines.

7 WORK CONTROL ISSUES

7.1 Unit 1 - June 14, 1995, Turbine-Driven Auxiliary Feedwater Pump Post-Maintenance Warmup Run

On June 14, 1995, the inspectors observed a post-maintenance warmup run of the Unit 1 turbine-driven auxiliary feedwater pump. The licensee developed Work Order 1-95-088724 to provide work instructions for the post-maintenance test. Work Order 1-95-088724 specified that the following activities be performed prior to opening Auxiliary Feedwater Pump Turbine Main Steam Supply Bypass Valves 1MS-0711 and -0712:

B. CHECK TURBINE OIL LEVEL AT INBOARD BEARING LEVEL GAUGE (BETWEEN SCRIBE LINES)

C. ENSURE 1-SK-2452A, AFWPT SPD CTRL, TO 100% OUTPUT

D. TURN THE LOCAL GOVERNOR SPEED CONTROL KNOB TO MINIMUM

E. ENSURE 1-HV-2452 IS LATCHED AND CLOSED

1. LOOSEN THE REMOTE SERVO DRAIN LINE FITTING AT THE GOVERNOR

2. REMOVE THE GOVERNOR COVER TO OPERATE THE SHUTDOWN ROD WHILE STROKING THE GOVERNOR SERVO TO BLEED AIR.

3. INSTALL COVER. TIGHTEN FASTENERS SNUG TIGHT.

The operator skipped these steps. He opened Valves 1MS-0711 and -0712 to prewarm the steam lines prior to the completion of Steps B through E3. This resulted in operation of the auxiliary feedwater pump turbine: (1) prior to the completion of the maintenance checks, (2) in an incorrect valve alignment, and (3) without speed control. Further, the technical staff had not arrived in the room to watch the warmup and the governor had not been filled with oil (an open item from a different work order).

Technical Specification 6.8.1 states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Revision 2, February 1978, Appendix A recommends that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures appropriate to the circumstances. The operator did not follow the work instructions in Work Order 1-95-088724 by opening Valves 1MS-0711 and -0712 sooner than specified. This is the first example of a violation of Technical Specification 6.8.1 (445/9513-01; 446/9513-01).

7.2 Unit 2 - June 21, 1995, Turbine-Driven Auxiliary Feedwater Pump Performance Verification Test

As discussed in Section 2.2, a test was performed on June 21, 1995, to investigate the cause of the unusual noise and confirm that the pump was not cavitating. During that test, operators did not set the speed controller to 0 percent output as was normally done. The inspectors reviewed the procedural controls associated with this activity.

The system engineers had provided the operators with a description of a performance verification test for the turbine-driven auxiliary feedwater pump. The test description directed the operators to use portions of previously approved procedures, which were not consistent.

The operators used System Operating Procedure SOP-304B, Revision 2, Section 5.1.2, to warmup the turbine-driven auxiliary feedwater pump. Step 5.1.2.B of Procedure SOP-304 directed the operator to lower Speed Controller 2-SK-2452 to 0 percent output. Following the warmup run, the licensee planned to run the pump using Operations Test Procedure OPT-206B, Revision 5, Section 8.3.3. The operators recognized that the speed controller needed to be at 100 percent to meet the initial conditions of Procedure OPT-206B. To resolve this conflict, the operator chose not to lower the speed controller during the warmup run, as required by Step 5.1.2.B of Procedure SOP-304B. He determined that the step was not applicable.

The inspectors noted that the decision not to set the speed controller at 0 percent resulted in a significantly higher than anticipated auxiliary feedwater turbine flow during the warmup run.

Operations Department Administration Manual Procedure ODA-407, Revision 5, Section 6.1.5 directed operations personnel to ensure procedure compliance by following numbered procedure steps or lettered substeps in sequence unless deviations are allowed by the procedure or otherwise specifically authorized by the shift manager. Section 6.2.9 allowed steps, which cannot be performed as written, to be marked not applicable in accordance with Section 6.3. Section 6.3.2 stated that the approval authority would ensure that nonperformance of the step would not violate the intent of the procedure.

The inspectors concluded that not performing Step 5.1.2.B altered the methodology of Procedure SOP-304B and that the operator exceeded his routine approval authority when he determined Step 5.1.2.B of System Operating Procedure SOP-304B was not applicable. The inspectors determined that the operator also authorized a performance verification test of the Unit 2 safety-related auxiliary feedwater turbine, which had not been appropriately reviewed and approved.

Technical Specification 6.8.1 states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33 recommends written procedures appropriate to the circumstances for the operation of the safety-related auxiliary feedwater system. On June 21, 1995, written procedures for the operation of the safety-related auxiliary feedwater system appropriate to the circumstances were not established and implemented. This is the second example of a violation of Technical Specification 6.8.1 (445/9513-01; 446/9513-01).

The licensee subsequently developed procedure change notices for turbine-driven auxiliary feedwater post-maintenance performance tests.

7.3 Review of Station Administrative Procedure STA-606, "Work Requests and Work Orders," Revision 22

The inspectors reviewed Procedure STA-606, "Work Requests and Work Orders," Revision 22, to determine the licensee's policy on procedure compliance related to work orders and noted that licensee personnel had consistently used the word "should" instead of "shall" in the work order performance section of the procedure.

The inspectors found that the use of the words "should" and "shall" in Procedure STA-606 was not consistent with the definitions in Procedure STA-202, "Administrative Control of CPSES Nuclear Production Procedures," Revision 24. In Section 4.1.4.6 of Attachment 8.B, licensee personnel were instructed to apply "shall", "should", and "may" in the following manner:

- shall - used for absolute requirements (normally reserved for regulatory requirements or commitments)
- should - used to indicate firm CPSES management expectations. Deviation is a departure from the norm and requires supervisory concurrence.
- may - used to indicate a permissive action. Neither a requirement nor a recommendation.

The inspector noted that the work order performance section of Procedure STA-606 used the word "should" to promulgate regulatory requirements and commitments. This established that requirements were management expectations which could be deviated from with supervisory concurrence. For example, Section 6.6.4 stated that "While completing the task the RWO," (responsible work organization) "**should**: . . . notify the Shift Manager immediately when it becomes apparent that the work cannot be completed within the Technical Specification allowed time, or if a surveillance test fails to meet its acceptance criteria . . . ensure that a security officer is present prior to opening a breach of a Vital Area or Protected Area boundary greater than 96 square inches . . . perform work in accordance with the instructions and in the sequence listed" (with some exceptions noted) ". . . stop work and notify the ANII or QC for any specified hold points . . . record the M&TE equipment number and calibration due date of any M&TE used for obtaining quantitative date on page two of the WO [work order]." The inspectors concluded that licensee management had not clearly communicated requirements related to work order performance to licensee personnel.

Technical Specification 6.8.1 states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33 recommends written procedures for administrative procedures for procedure adherence and that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures appropriate to the circumstances.

Regulatory Guide 1.33, Revision 2, February 1978 endorses American National Standard (ANS) N18.7-1976/ANS-3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants." Standard N18.7, Section 2.1, states that the definitions are applicable to this Standard, and defines for **shall and should** that the word "shall" is used to denote a requirement and the word "should" is used to denote a recommendation. Section 5.2.2, states that procedures shall be followed, and the requirements for use of procedures shall be prescribed in writing.

The failure of Station Administrative Procedure STA-606, "Work Requests and Work Orders," Revision 22, to include wording which clearly established requirements to perform maintenance on safety-related equipment in accordance with applicable regulations and commitments is the third example of a violation of Technical Specification 6.8.1 (445/9513-01; 446/9513-01).

Licensee personnel planned to rewrite Procedure STA-606 as necessary to ensure regulatory requirements and commitments were clearly communicated to station personnel. During interviews, several site personnel stated it was their belief that, in general, regulatory requirements were being followed.

7.4 Conclusions

The inspectors concluded that procedural control of some activities was weak. One example of not following procedure direction was observed, another example of inadequate procedure direction was identified. In addition, the governing procedure for the control of maintenance activities did not clearly specify the need to implement activities in accordance with procedure direction.

ATTACHMENT

EXIT MEETING AND ATTENDEES

1 PERSONS CONTACTED

1.1 Comanche Peak

B. Bhujary, Project Engineering Manager
M. Blevins, Plant Manager
D. Buschbaum, Technical Compliance Manager
R. Calder, Engineering Analysis Manager
R. Carver, Engineer
D. Dillinger, Nuclear Overview Evaluator
C. Feist, Consulting Engineer
T. Gilder, Maintenance Engineering Supervisor
T. Hope, Regulatory Compliance Manager
J. Kelly Jr., Vice President Engineering Support
S. Lakdawala, Civil Engineering Supervisor
F. Madden, Engineering Overview Manager
T. Marvray, Technical Programs Supervisor
G. Merka, Senior Nuclear Specialist
J. Meyer, Mechanical Engineering Supervisor
W. Morrison, Maintenance Engineering Manager
N. Paleologos, Vice President Operations
P. Passalugo, Civil Engineering Supervisor
D. Rencher, BOP Systems Supervisor
S. Smith, Work Control Manager
M. Sunseri, Project Manager
J. Taylor, Procurement Engineering Supervisor
L. Terry, Group Vice President
R. Walker, Regulatory Affairs Manager
D. Woodlan, Docket Licensing Manager
L. Yeager, Staff Assistant

1.2 NRC Personnel

E. Collins, Acting Engineering Branch Chief
A. Gody, Senior Resident Inspector

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

2 EXIT MEETING

An exit meeting was conducted on July 20, 1995. During this meeting, the inspectors summarized the scope and findings of the inspection. The licensee acknowledged the findings presented at the exit meeting. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

During the exit meeting, licensee personnel stated that they did not agree that the wording of Procedure STA-606 using "should" instead of "shall" was a violation of NRC requirements. During additional discussions subsequent to the exit meeting, licensee personnel reasoned that, since management expected personnel to comply with regulatory requirements and commitments, the use of the word "should" was equivalent to the use of the word "shall." They reasoned that deviation from written instructions requires supervisor concurrence and that supervisors would not give concurrence to deviate from instructions, if they were aware that the instruction was a requirement or commitment. The licensee also stated that, during performance monitoring, they have not observed site personnel failing to meet regulatory requirements or commitments because of the use of the word "should."