APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-482/91-36 Operating License No.: NPF-42

Docket: 50-482

Licensee: Wolf Creek Nuclear Operating Corporation
P.O. Box 411
Burlington, Kansas 66839

Facility Name: Wolf Creek Generating Station

Inspection At: Coffey County, Burlington, Kansas

Inspection Conducted: December 18, 1991, through January 25, 1992

Inspectors: G. A. Pick, Senior Resident Inspector
L. L. Gundrum, Resident Inspector
C. J. Paulk, Reactor Inspector

Approved: A. T. Howell, Chief, Project Section D, Division of Reactor Projects — Date: 2-24-92

Inspection Summary

Inspection Conducted December 18, 1991, through January 25, 1992 (Report 50-482/91-36)

Areas Inspected: Routine, unannounced inspection including plant status, followup of previously identified NRC items, operational safety verification, surveillance observations, maintenance observations, refueling activities, and plant startup from refueling.

Results: During this inspection period, three violations were identified. One violation pertained to three examples of failure to have adequate procedures and a second violation pertained to two examples of failure to follow procedures (Sections 4.2, 4.3, 6.2, and 5.3 and 8.0, respectively). The third violation pertained to inadequate corrective actions (Sections 3.2).

Two examples identified during this inspection period are indicative of continuing weaknesses in the licensee's ability to assess the safety significance of conditions affecting safety-related systems or components and the licensee's ability to correct the root causes of problems in a timely manner (Sections 3.2 and 5.2).

Surveillance performance declined from its previous high level during this inspection period. Several problems occurred during the performance of surveillance activities because of a failure to follow procedures or because of an inadequate procedures (Sections 4.3, 4.4, 5.3, 6.3, and 8.0). The adequacy of centrifugal charging pump minimum flow will be tracked as an unresolved item pending further inspection followup (Section 5.4).

Maintenance performance was mixed during this inspection period. The replacement and repair of two relief valves were generally well performed; however, a poor radiological practice of leaning over a barrier for a contaminated area was identified by a licensee health physics technician and similarly observed by the NRC (Sections 6.1 and 6.4). The root cause of a recurring problem associated with the TDAFW pump trip and throttle valve was identified; however, the valve cycling problem had occurred at least two other times, with only one previous occurrence explicitly documented (Section 6.3). Incorrect fuses were being installed because of I&C personnel reliance on incorrect vendor drawings. Long-term corrective actions associated with the fuse control program will be tracked by an inspection followup item (Section 6.5).

Plant Operations Section performance was also mixed during this inspection period. Plant operator action was conservative when a low component cooling water operating temperature condition was identified (Section 5.2), and prompt operator action minimized the effects of a steam generator (SG) level transient that occurred when the wrong main steam pressure transmitter was taken out of service (Section 5.3). However, several licensed operators failed to detect that neither of the centrifugal charging pumps was available for automatic initiation while the plant was in Mode 4 (Section 4.2). The inspectors noted one example of a general operating procedure that had a relatively large number of temporary changes. This is considered a weakness (Section 4.2).

The refueling outage was carefully controlled. However, the outage was extended because of a failed fuel rod, delays encountered during cleaning of the CCW heat exchangers and manway repairs, and difficulties in trying to stop the leakby of the new boron injection tank inlet bypass valves. The majority of the outage extension was attributed to resolving significant NRC and licensee-identified MOV deficiencies (Section 7).

Overall, the plant startup, approach to criticality, and core physics tests were well performed. All data met the design specifications which verified the core design (Section 8).

A list of acronyms and initialisms is provided in Attachment 1 of this report.

DETAILS

1. Persons Contacted

B. D. Withers, President and Chief Executive Officer
J. A. Bailey, Vice President, Operations
F. T. Rhodes, Vice President, Engineering and Technical Services
O. L. Maynard, Director Plant Operations
R. S. Benedict, Manager, QC
K. B. Clair, Maintenance Engineering
T. F. Deddens, Jr., Outage Manager
R. B. Flannigan, Manager, Nuclear Safety Engineering
C. W. Fowler, Manager, Instrumentation & Control (I&C)
W. J. Goshorn, Planning Engineer, Kansas Electric Power Cooperatives,
R. L. Gourley, Supervisor, Mechanical Maintenance
L. W. Holloway, Supervisor, Engineering,
R. W. Holloway, Manager, Maintenance and Modifications
D. M. Hooper, Engineering Specialist
W. M. Lindsay, Manager, Quality Assurance
R. L. Logsdon, Manager, Chemistry
B. T. McKinney, Manager, Training
T. S. Morrill, Manager, Radiation Protection
W. T. Muilenburg, Licensing Engineer
D. G. Moseby, Supervisor, Operations
W. B. Norton, Manager, Technical Support
C. E. Parry, Director, Quality and Safety
A. L. Payne, Manager, Supplier/Material & Quality
J. M. Pippin, Director, Nuclear Plant Engineering (NPE)
G. P. Rathbun, Manager, NPE, Wichita
C. E. Rich, Jr., Supervisor, Electrical Maintenance
B. B. Smith, Manager, Modification
J. D. Stamm, Manager, Plant Design Engineering
J. D. Weeks, Manager, Operations
M. G. Williams, Manager, Plant Support

In addition to the above, other licensee personnel were contacted during the inspection.

2. PLANT STATUS

At the start of the inspection, the plant was in Mode 5 (cold shutdown). The majority of the work effort during this inspection period pertained to Valve Operation Test and Evaluation System (VOTES) testing of motor-operated valves (MOVs). The plant reached Mode 4 on January 3, 1992, and Mode 3 on Monday, January 6. Because of a leaking relief valve on the Train B residual heat removal (RHR) line, the plant was cooled down to Mode 4 in order to repair the valve. After repair of the relief valve, the unit reentered Mode 3 on January 7. Mode 2 was entered on January 12 and Mode 1 was entered on January 14, ending an outage of 117 days. The plant was at 100 percent thermal power, 1170 megawatt, at the end of the inspection period.

3. FOLLOWUP ON PREVIOUSLY IDENTIFIED NRC ITEMS (92701)

3.1 (Open) Unresolved Item (482/9134-02): Operability of MOVs

During a recent inspection of the licensee's Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," program, the inspectors questioned the operability of a number of safety-related MOVs at WCGS. The operability of the MOVs was questioned because of problems with motor sizes, spring-pack sizes, torque-switch settings, and test results.

The licensee identified approximately 37 valves with one or more of the above problems but did not complete the valve operability and safety significance reviews by the end of the inspection period. However, all MOVs identified with these types of deficiencies were corrected prior to the restart of the unit at the end of the fifth refueling outage. This item will remain open pending completion of the licensee's evaluation and subsequent inspection by the NRC.

3.2 (Closed) Unresolved Item (482/9131-03): Essential Service Water (ESW) System Water Hammer During Diesel Generator (DG) Testing

This item was considered unresolved pending NRC review of the circumstances associated with the licensee's evaluation and resolution of a previous ESW water hammer event. On November 10, 1991, a water hammer event occurred in the vicinity of Containment Cooler A during a DG A sequential load test. The licensee implemented a procedure change that prevented a similar water hammer from occurring during the DG B sequential load test. The procedure change specified flow paths other than the containment coolers in order to sufficiently load the ESW pump. The path to the coolers was not a test requirement because the test verified the ability of the DG to reject the ESW pump, the single largest load. Changing the test lineup to prevent further water hammer events, however, appeared to be a symptomatic repair. The inspector considered this to be a weakness.

The licensee evaluated the effects of the water hammer by conducting a walkdown of the affected ESW piping and containment coolers and determined that no damage occurred. Maintenance personnel stroked one snubber near the affected containment cooler. Additionally, maintenance personnel verified that each snubber on ESW Train A inside containment was stroke tested at least once between 1988 and 1991 with no failures identified.

From discussions with licensee personnel and review of documentation, the inspector determined that the water hammer at the containment coolers was initially identified as a problem in November 1988 and documented on Engineering Evaluation Request (EER) 88-EF-08. There existed no entries during this period (November 1988) in the control room log book about a water hammer event. The inspector identified no evidence indicating that the affected ESW piping was walked down in 1988 to identify the effects of the the water hammer event.

In June 1991, engineering issued a clarification of disposition which requested additional information on the severity and defined locations of the water hammer that occurred in June 1988. From discussions with the licensee, the inspector determined that, when the ESW pump is stopped and restarted, the weight of the water in the vertical sections of pipe to the containment coolers caused backflow through the ESW pump. The total height of the vertical section of the 14-inch pipe is 100 feet. A void is generated at the top of the piping and, upon pump restart, the water hammer occurred when the void was filled with water.

The inspector determined that EER 88-EF-08 is on the 1992 work plan. A job authorization summary was developed to ensure that engineering conducts a transient analysis dynamic load in the ESW line. The licensee will review other methods to prevent further water hammers in the line. The licensee is considering placing a check valve on each ESW line on the containment cooler inlet as low in elevation in the containment as possible.

The water hammer event that occurred in 1988 potentially affected system operability but was not properly evaluated and documented. No information was provided to the inspectors in November 1991 regarding the previous evaluations resulting from the November 1988 event. EER 88-EF-08 was not listed in the 1990 or 1991 work planning schedule book, which indicated that the concern was not in the licensee's program for resolution during Refuel Outages IV or V. This is a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to take prompt corrective action associated with the water hammer event identified in 1988 (482/9136-03). The NRC staff believes, had appropriate actions been taken in 1988, the 1991 event would not have occurred.

4. OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements and that the licensee's management control systems were effectively discharging the licensee's responsibilities for continued safe operation. The inspectors monitored licensee activities related to: a leaking relief valve, centrifugal charging pump (CCP) inoperability in Mode 4, intermediate range monitor (IRM) calibration procedure inadequacy, missed surveillance tests, training of licensed operators, and security. The methods used to perform this inspection included direct observation of activities and equipment, control room observations, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety-system status and limiting conditions for operation (LCO), corrective actions, and review of facility records.

4.1 Relief Valve Leakage

On January 6, 1992, with the plant in Mode 3, Relief Valve EJ-8856B, "RHR to Accumulator Injection Discharge Loops 3 and 4, Relief Valve," on the Train B RHR discharge line was found to be leaking. The leakage out of its weep hole caused a spray of water in the south piping penetration room. The cause of the leakage was determined to be a failed bellows. The Director, Plant Operations ordered a reduction to Mode 4 to repair the valve. Although the Train B RHR line was drained, leakage continued from the relief valve tailpipe drain line. After several hours of deliberation, the licensee decided to attempt to relieve the pressure from the recycle holdup tank drain line. Operations opened Recycle Holdup Tank Drain Line Valve HE-V179, which stopped the leakage through the weep hole of Relief Valve EJ-8856B. The subsequent replacement of the relief valve is discussed in Section 6.1.

4.2 Inoperable CCP in Mode 4

On January 7, 1992, after shift turnover, the operations supervisor noted at approximately 7:45 a.m. that the CCP A control switch was in the pull-to-lock position, thus rendering the pump unavailable for automatic operation. CCP B had been removed from service by use of a clearance order (danger tag). Therefore, both trains of an emergency core cooling system (ECCS) subsystem were inoperable. TS 3.5.3 requires, as a minimum, one ECCS subsystem that includes one OPERABLE CCP in Mode 4. With no subsystem operable, TS 3.5.3 requires restoration of one subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within 20 hours. The plant had been in Mode 4 since 9:21 p.m. on January 6, 1992, and the operations supervisor recognized that this CCP configuration was not in accordance with TS. After discussion with operators on duty, CCP A was restored to operable status and the positive displacement pump (PDP) was removed from service. At the time of discovery, the allowed outage time specified in TS 3.5.3 had not been exceeded, therefore, no violation of TS 3.5.3 occurred.

The inspector reviewed the circumstances that resulted in the inoperable CCP. Procedure GEN 00-006, Revision 17, "Hot Standby to Cold Shutdown," Step 4.21.2, requires that, within 4 hours after entering Mode 4 from Mode 3 or prior to temperature of one or more of the reactor coolant system (RCS) cold legs decreasing below 325°F, whichever occurs first, the operator determine which CCP shall remain OPERABLE and to rack out the breakers for the other CCP and PDP. The operator listed CCP A as OPERABLE, signed off racking out the breaker for CCP B, but marked "Not Applicable" for the step racking out the breaker for the PDP. The inspector considered this step inappropriate to the circumstances because it was not written with enough guidance to preclude placing a CCP in the pull-to-lock position while the plant was in Mode 4. Failure to maintain one CCP operable is the first example of a violation of TS 6.8.1.a for failure to have an adequate procedure (482/9136-01).

The immediate corrective action was to require each shift supervisor to review the precautions and limitations with his crew prior to implementing the general procedures used to change modes. Long-term corrective action may include submission of a TS change.

In followup discussions with the reactor operator and supervising operator involved, they stated their concern about running CCP A at low flows because of cavitation concerns. The operators failed to realize that, although placing a CCP in pull-to-lock with the other CCP out of service is allowed in Modes 5 and 6, this condition is not allowed in Mode 4. The inspector reviewed Procedure GEN 00-006 and found that the first four pages of the procedure documented numerous precautions and limitations. Step 2.2.11.1 on page 3 states "The PDP may be used for charging and seal injection in Modes 5 and 6 provided the OPERABLE CCP hand switch is in PULL TO LOCK and one CCP is DANGER TAGGED out. If OPERABLE CCP must be STARTED, PDP must be SHUT DOWN." The precaution is placed there to provide information on cold overpressure protection. The precaution does not address Mode 4 or the TS requirements relating to Mode 4. The step requiring the Mode 4 requirement to place a CCP in service is on page 10 of the procedure. On the basis of discussions with licensed operators from both shifts involved, the inspector determined that the failure to recognize the TS and procedural requirements resulted, in part, from the infrequent amount of time the unit is operated in Mode 4. The oncoming shift failed to question the off-going crew during the shift turnover about the pump status, which is why the condition was not detected during shift turnover.

The inspectors also considered the relatively large number (eight) of temporary procedure changes appended to the procedure to be a weakness. Although not a factor in this incident, the failure to incorporate the relatively large number of temporary changes into the procedure as a revision may distract the operators and could lead to errors.

4.3 Incorrect IRM Setpoints

On January 13, 1992, during a posttest review of Procedure STS IC-235, Revision 6, "Analog Channel Operational Test Nuclear Instrumentation System Intermediate Range N-35 Protection Set I," and STS IC-236, Revision 6, "Analog Channel Operational Test Nuclear Instrumentation System Intermediate Range N-36 Protection Set II," an I&C group supervisor determined that the intermediate range power level trip setpoint of 25 percent power was set incorrectly. STS IC-235 was completed at 9:35 p.m. and STS IC-236 was completed at 10:24 p.m. on January 11. The setpoints were set at approximately 35 percent and were based on Operating Cycle 5 data (the previous operating cycle). At the time of discovery, the plant was operating in Mode 2 for low power physics testing. The I&C group supervisor informed control room personnel, and the shift supervisor immediately determined that special test exception provided for in TS 3.10.3 for low power physics testing no longer applied.

Since TS 3.10.3 no longer applied, the shift supervisor ensured compliance with the applicable TS. The shift supervisor entered TS 3.0.3 because both IRMs were determined to be inoperable at 7:35 a.m. TS 3.0.3 requires, in part, that, within 1 hour, the plant be placed in HOT STANDBY, Mode 3, within the following 6 hours. I&C personnel reperformed STS IC-235, Revision 6, using the correct data on January 13. After IRM A was restored to service at 9:19 a.m., the shift supervisor exited TS 3.0.3 and TS Table 3.3-1, Item 5, Action Statement 3b, for one IRM out of service. After I&C completed recalibrating IRM B in accordance with STS IC-236, Revision 6, at 9:37 a.m., the shift supervisor exited TS 3.3-1, Item 5. Reactor protection was unaffected because the power range neutron flux low trip was still provided by the unaffected power range detection circuitry.

From discussions with licensee personnel, the inspector determined that the intermediate range channels were calibrated using the data that was applicable during the previous operating cycle. Data that provides conservatisms of 10 percent for two new IRM detectors and 10 percent for a low leakage core were not incorporated into the calibration procedure. This information was documented on a procedure change attached to the initial test, and it was also attached to STS IC-235 and -236. However, the technicians failed to incorporate the information from the procedure change into the body of the procedure. The failure to incorporate the change into the procedure caused the I&C technician to readjust the IRM setpoints on the basis of Operating Cycle 5 data.

The inspectors considered STS IC-235 and STS IC-236 inappropriate to the circumstances because licensee personnel failed to incorporate a temporary procedure change into the applicable sections of STS IC-235 and STS IC-236. This is the second example of an apparent violation of TS 6.8.1.a (482/9136-01) for failure to have an adequate procedure. Although this violation was detected by the I&C supervisor during the performance of his duties, this violation is being cited because it occurred as a result of inattention to detail during the performance of safety-related activities.

4.4 Missed Surveillance Tests

On January 14, 1992, during a review of Procedure GEN 00-002, Revision 20, "Cold Shutdown to Hot Standby," the licensee determined that Steps 4.44.2.4 and 4.44.2.5 were not performed in Mode 3 prior to entering Mode 2 at 5:25 a.m. on January 12. The two steps involved the performance of STN AE-001, "Main Feedwater Isolation Valve Accumulator Discharge Test," and STN AE-002 "Feedwater System Check Valve Leak Rate Test." From discussions with plant management, the inspector determined that the requirement to perform STN AE-002 was the result of a commitment in Licensee Event Report (LER) 85-046. This LER stated that the feedwater system check valves would be tested periodically. Because Procedure STN AE-002 was missed, the licensee placed this surveillance or the forced outage list. As a result of not performing STN AE-001, the licensee verified that the nitrogen pressures in the accumulator was within the acceptance range to ensure operability of the main feedwater isolation valves. The test was subsequently completed on January 14.

4.5 Training Performed Prior To Startup

On December 31, 1991, the inspector attended licensed operator training, which was performed prior to restarting the plant. The scope of the training was changes to emergency operating procedures which resulted from the re-evaluation of the operation of certain MOVs. The major change w the operation of the boron injection tank inlet and outlet valves, EM HV 8801A/B and -8803A/B. If required to close the inlet valves, it may be necessary to shut off the operating CCP pump since the current valve design cannot close against the shutoff head of the pump with a depressurized RCS. The inspector considered the training to be well organized and well presented.

4.6 Security Observations

The inspectors monitored security officer activities in the secondary alarm station. The officers were attentive and familiar with their assigned duties. The inspectors verified that the protected area was adequately illuminated and free of transient materials.

Conclusions

Several licensed operators failed to ensure that at least one coolant charging pump was available for automatic operation while the plant was in Mode 4. This resulted because of an inadequate general operating procedure. In addition, the licensee identified other examples of failure to have adequate procedures. The inspectors also noted one example of several temporary procedure changes associated with a general operating procedure. The inspectors considered the failure to incorporate numerous temporary changes, as appropriate, into revised procedures to be a weakness.

The training given to all licensed operators on changes to the emergency operating procedures was well organized and well presented. Security officers were attentive and familiar with their assigned duties at the secondary alarm station.

5. SURVEILLANCE OBSERVATIONS (61726)

The purpose of this inspection was to ascertain whether surveillance of safety-significant systems and components was being conducted in accordance with TS. Methods used to perform this inspection included direct observation of licensee activities and review of records.

5.1 RCS Check Valve Leak Testing

On January 6, 1992, licensee personnel determined that a water hammer "noise" occurred on the SI Accumulator B line. The licensee determined that pipe movement and a loud noise occurred at the time electricians opened SI Accumulator Isolation Valve EP HV-8808B.

Following the event, quality control (QC) inspectors and engineers walked down the affected sections of the piping. The QC inspector and the engineers identified no problems during their walkdown except for rotated pipe clamps for two snubbers. Additionally, a 1-inch movement of the line occurred as determined by a scratch along the pipe. Engineering could not positively verify that the line movement occurred during the water hammer "noise"; however, NPE determined that the snubbers were subjected to forces equal to 60 percent of the maximum capability and remained operable.

On January 8, the licensee completed the check valve leak test for Valve BB V-8948A, SI Accumulator to Loop 2 check valve. While opening SI Accumulator Isolation Valve EP HV-8808A, the auxiliary building operator reported that a loud "noise" (similar to a check valve seating) occurred when Valve EP HV-8808A was opened. After this second occurrence, engineering decided that the "noise" that was being heard may be caused by the isolation valve opening under high differential pressure conditions. The engineers determined that the check valves could not seat with sufficient force to cause the "noise." The QC walkdown of the discharge line for SI Accumulator A identified no problems.

During the restoration following the check valve leak tests for BB V-8948C and -8948D, engineers were present and verified that the "noise" was pressure equalizing across the associated accumulator isolation valves. This issue was resolved by the licensee (see Section 6.2). The inspector observed the engineers' work activities during restoration of Isolation Valve EP HV-8808D. No problems were identified.

5.2 Low CCW System Operating Temperature

On January 19, 1992, during the performance of STS EG-205, Revision 7, "Component Cooling Water System Inservice," Train A CCW system operating temperature dropped below 60°F (CCW minimum operating temperature) after CCW Pump C was started. The operators declared CCW Train A inoperable and entered the action statement for TS 3.7.3 because the temperature was below the required minimum. CCW heat exchanger outlet temperature is verified and logged three times a day to ensure the temperature is above 60°F. CCW Pump A was left running and temperature in the loop was restored within 1 1/2 hours.

The inspector noted that the control room logs referenced EER 85-EG-11. This evaluation recommended throttling ESW or service water flow to the CCW heat exchangers using Valves EF HV-51 for CCW Heat Exchanger A and EF HV-52 for CCW Heat Exchanger B. These valves were recommended because they receive a safety signal to go full open during accident conditions. The evaluation did not address the potential for cooling the CCW system below 60°F during an accident when the valves would be in the full open position. The inspector discussed with engineering personnel the components cooled by CCW and the potential impact of lower than design temperatures. The design value of 60°F is part of the design criteria stated for the safety injection (SI) and charging pump vendors as a limit on the temperature for the lube oil coolers. It is also the limit specified by the reactor coolant pump vendor as the limiting inlet temperature for the thermal barrier cooling coil, motor air cooler, and bearing coolers.

Because of the necessity to control microscopically induced corrosion in the ESW system, the requirement to reduce flow to the CCW heat exchanger was reexamined. In 1988, a plant modification request was initiated to install temperature control valves on the outlet of the CCW side of the heat exchanger rather than throttling ESW flows. This modification was scheduled for Refuel Outage V, but was delayed because of the inability to obtain the necessary parts. The modification is now being considered for Refuel Outage VI. Although the licensee had known about this condition for several years, no evaluation had been performed to assess the effect of low CCW system water temperature on safety-related equipment. In addition, the inspector considered the throttling of the CCW heat exchanger valves to be a symptomatic repair because the throttling of the valves to raise CCW temperature may not be effective under accident conditions since the valves would be repositioned to the full open position. However, after inspector questioning, the licensee subsequently determined that CCW system operating temperatures as low as 35°F were acceptable. Although this issue is not being cited as a violation of 10 CFR Part 50, Appendix B, Criterion XVI, the inspectors considered this to be indicative of the same weaknesses in self-assessment and corrective action capabilities as discussed in Section 3.2.

5.3 Inadvertent Isolation Of Main Steam Pressure Transmitter

On January 18, 1992, during the performance of STS IC-507A, Revision 5, "Calibration Steam Line Pressure Transmitters," an I&C technician valved out Main Steam Pressure Transmitter AB PT-525 rather than AB PT-526, which was required to be valved out by Step 5.10.4. The pressure transmitter provides a signal that is used for density compensation of the steam flow channel. Valving out the transmitter resulted in the receipt of a feedwater flow/steam flow mismatch alarm and a level deviation alarm on SG B. The operators took prompt and effective action to manually control the feedwater regulating valve in order to restore SG level. The cause of this event can be attributed to inattention to detail. This is the first example of a violation of TS 6.8.1.a (482/9136-02) for failure to follow an approved procedure.

5.4 Testing Of CCPs

On January 1, 1992, a temporary procedure change was made to STS BG-100B, Revision 11, "Centrifugal Charging System 'B' Train Inservice Pump Test," to verify the capability to shut and reopen Valve BG HV-8111 (charging pumps minimum flow valve). Check Valve BG V095, located downstream of Valve BG HV-8111, is normally verified to be open and capable of passing 60 gallons per minute (gpm) to meet the surveillance requirements of TS 4.0.5, ASME Section XI, "Inservice Testing." The 60 gpm value was provided by the pump manufacturer as the minimum flow to prevent pump damage, and the 60 gpm value was committed to the NRC in response to NRC Bulletin 88-04, "Potential Safety Related Pump Loss." During the performance of the test, a Controlotron flow instrument was placed on the 2-inch line between Valves BG HV-8111 and BG V095 to verify that MOV BG HV-8111 opened and closed properly. This flow instrument was in addition to the Controlotron located downstream on the 3-inch seal injection return and excess letdown line. The flow value obtained on the 2-inch line by the Controlotron was 58.1 gpm. The flow measured from the 3-inch line downstream of BG HV-8111 was 64.85 gpm. The licensee was evaluating the inconsistency of the flow readings and test procedure concerns under Performance Improvement Request (PIR) TS 91-0238, "Inadequacy of Inservice Test Procedures."

The licensee considers the CCP and check valve operable because one of two Controlotron readings exceeded the minimum acceptance criteria of 60 gpm. The inspector reviewed the surveillance test data for Check Valve BG V095 since 1985. Several flow test failures occurred (i.e., an indicated low flow condition); however, there was not a trend indicating degraded performance. For example, 12 tests were performed since September 1989. Four tests resulted in flows between 62.2 and 64.85 gpm; one test between 65 and 70 gpm; and seven tests with flows greater than 70 gpm. The adequacy of centrifugal charging pump minimum flow will be tracked by an unresolved item (482/9136-04) pending further inspection followup.

5.5 Additional Surveillance Testing

The inspectors also observed or reviewed the following surveillance tests:

- STS AL-201, Revision 9, "Auxiliary Feedwater System Inservice Valve Test;"
- STS EM-202, Revision 3, "Safety Injection System Inservice Valve Test;"
- STS AE-205, Revision 8, "Feedwater System Inservice Valve Test;"
- STS EM-100B, Revision 7, "Safety Injection Pump B Inservice Pump Test;"
- STS EG-001, Revision 6, "CCW Valve Check;"
- STS SE-001, Revision 10, "Power Range Adjustment;" and
- STS BB-004, Revision 8, "RCS Water Inventory Balance."

Conclusions

The failure to resolve a low CCW system temperature condition in a timely manner is considered a weakness. Although this problem was identified several years ago, the licensee had not evaluated (until recently) the effect of low CCW temperature on safety-related components. In addition, a permanent resolution has not been implemented.

As a result of inattention to detail during an I&C surveillance, the wrong main steam pressure transmitter was valved out. This resulted in a level deviation alarm associated with SG B. The operators took prompt and effective action to restore SG level.

The adequacy of centrifugal charging pump minimum flow will be tracked as an unresolved item pending further inspection followup.

6. MONTHLY MAINTENANCE OBSERVATIONS (62703)

The purpose of inspections in this area was to ascertain that maintenance activities on systems and components were conducted in accordance with approved procedures and TS. Methods used in this inspection included direct observation, personnel interviews, and records review. Observations of selected maintenance activities are provided below.

6.1 Replacement of Relief Valve

The inspector observed mechanics replace Relief Valve EJ 8856B, under Work Request (WR) 00172-92 on January 7, 1992. Since the work was performed in a contaminated area, two health physics (HP) technicians were present during the work activity. The mechanical maintenance personnel brought to the job site a replacement relief valve that had successfully passed acceptance tests. The workers removed four bolts from the inlet and outlet of the relief valve, replaced flexitallic gaskets, replaced the valve, and retorqued the bolts. QC personnel observed the torquing of the bolts. Overall, the work was performed well and HP coverage was good.

The inspector observed that a plastic dust cap was inserted in the weep hole of Valve EJ 8856A, "RHR to Accumulator Injection Discharge Loops 1 and 2 Relief Valve." The inspector found another plastic dust cap inserted in SI Pump B suction relief valve. The plastic caps are inserted in the weep hole for protection and should be removed prior to installing the valve. The licensee determined that the caps did not adversely affect the operability of the relief valve.

6.2 Accumulator Tank B Outlet Isolation Valve Repair

Following testing of Check Valve, BB V-8948B (as discussed in paragraph 5.1), test personnel attempted to manually open the motor-operated SI Accumulator Isolation Valve EP HV-8808B as specified in STS PE-019E, Revision 6, "RCS Isolation Check Valve Leak Test." When the personnel tried to open and manually lift the valve off of its closed seat, they heard a grinding noise and found it difficult to open the valve. Sometime later the operators noticed that the control switch was in the "maintain closed" position instead of "normal." The "maintain closed" position ensures that the actuator control circuit forces the valve closed.

The operators returned the control switch to "normal," and the test personnel manually opened the valve from its closed seat. Operators cycled the valve. The valve opened without any problems noted; however, when the valve was closed, the test personnel noted a grinding noise.

From discussions with licensee personnel, the inspector determined there was no safety significance to the valve's potential inability to close under the existing plant conditions. Operations reviewed the consequences of opening the valve, racking out the breaker while in Modes 1, 2, or 3 above a 1000 pounds per square inch gage (psig). TS 3.5.1 requires the valve to be opened with power removed in these modes. Whenever the emergency operating procedures require the valve to be closed, power is restored and the valve is remotely closed from the control room. If the valve fails to close, compensatory actions require venting the nitrogen from the accumulator to lower the accumulator pressure. When the accumulator pressure is lowered, the check valves in the accumulator line will stop backleakage from the RCS.

Since the valve was required to be opened and power removed, WR 00249-92 was issued to troubleshoot and/or repair Valve EP HV-8808B. While working on the motor operator, a mechanic noted that the gear ratio did not agree with the design gear ratio. The mechanic determined that the nameplate data and design data agreed and specified an overall gear ratio of 38.3 rather than the identified ratio of 40.66. Subsequent to the licensee notifying the vendor of this problem, the vendor determined that the actual shipped gear set had a ratio of 40.66. The other accumulator isolation valves were similarly affected.

The licensee evaluated the change in the gear ratio on valve operability. Because the gear ratio increased, the valve takes longer to stroke, but also develops greater torque; however, the valve was tested with this gear ratio and stroke times were acceptable. The increased torque added margin to the valve's ability to close under degraded voltage conditions. The valve will not overthrust into the closed seat since the torque continues to trip at the same point during valve stem travel. The licensee informed the inspector that the vendor was reviewing their documents and the circumstances surrounding how a different gear set was shipped.

The damaged actuator components included the tripper fingers, worm shaft clutch, worm shaft clutch gear, and the hand wheel clutch pinion. The repair and replacement of these components were conducted by approved procedures. The postmaintenance test consisted of stroking the valve, which included a static VOTES test. The inspector identified no problems during the review of the work package.

From discussions with the licensee, the inspector determined the test procedure failed to provide sufficient guidance for manually lifting the valve from its closed seat. In order to prevent the "noise" that occurs when restoring these valves (see paragraph 5.1), the licensee implemented a change to Procedure STS PE-19E, Revision 6, to have the test personnel manually move the valve from its seat, allowing pressure to equalize. The operators would then complete the valve stroke by using the hand switch on the main control board. The procedure change failed to require the operators to place the hand switch to "normal" from the "maintain close" position. The failure to ensure that the procedure was adequate is the third example of a violation of TS 6.8.1.a (482/9136-01) for failure to have an adequate procedure.

6.3 Turbine Driven Auxiliary Feedwater (TDAFW) Pump Problems

On January 9, 1992, the inspector reviewed activities related to troubleshooting and repair of deficiencies identified during testing of the TDAFW pump turbine. During testing, the governor valve cycled and the red control board light blinked continually. Operations declared the pump inoperable and entered the appropriate TS. The governor valve cycling and control board light blinking problems were investigated and repaired under WR 00251-92. The troubleshooting directions were written to investigate the electric governor mechanism (EGM). The EGM was fluctuating and, in accordance with vendor manual instructions, the I&C technicians adjusted the EGM stability potentiometer. The potentiometer was adjusted from a setting of 5.0 to 7.5, which reduced the severity of fluctuations. This corrected the governor valve cycling and the red control board indication light blinking.

During postmaintenance testing when the TDAFW pump was tripped and reset, however, the trip and throttle valve, FC HV-312, cycled open and closed when the "open" push button was pushed. Licensee personnel determined that the cycling of FC HV-312 was caused by the lever arm on the turbine overspeed limit switch flipping onto the wrong side of the roller plate. The trip and throttle valve cycling problem was investigated and corrected under WR 00250-92. The I&C technicians found the limit switch contact arm on the incorrect side of the roller assembly. This problem occurred twice and, after the second event, the technicians determined that the method used by the operator to trip the turbine locally caused the contact arm to flip to the wrong side of the roller assembly. The operator pulled the trip lever outward by reaching above his head. The linkage flexes and, with a small amount of added force, causes the contact arm to flip under the roller assembly. From review of the contact arm-to-roller assembly connection, the technicians determined that the contact arm had insufficient engagement with the roller assembly.

The licensee's review of the work history surrounding the limit switch identified two previous similar occurrences. The most recent occurrence was explicitly documented, while the other occurrence was not. The licensee initiated PIR 92-0059 for the lack of documentation on the problem and subsequent corrective action. The licensee initiated WR 00301-92 requesting that engineering review the design of the roller assembly. The mechanics requested that the roller assembly be slotted to optimize the engagement between the contact arm and the assembly.

6.4 Repair of PDP Relief Valve

On January 10, 1992, the auxiliary building watch found a leaking weld on the flange of Relief Valve BG-8118 located on the PDP discharge piping. As of the end of the inspection period, the licensee had not determined the cause of the leaking flange. The inspector observed the placement of a freeze seal on the supply piping from the volume control tank to the PDP. The freeze seal was installed by Temporary Modification 92-02-BG and performed under WR 00322-92. Since the work was performed in a contaminated area, HP personnel monitored the activities. No difficulties were encountered during the job.

The inspector also observed the postmaintenance testing of the relief valve, following replacement of the bellows. Two maintenance personnel conducted the pop test and seat leakage check under WR 00318-92. The work was performed in the hot machine shop within a roped off area for contamination control. Maintenance supervision, QC and HP personnel, and the inspector observed the work from outside of the controlled area. The HP technician had to remind personnel several times not to lean across the barrier. The inspector considered this to be a poor radiological work practice. All other activities associated with this work request were properly performed.

6.5 Fuse Control

During the inspection period the inspector reviewed nine reportability evaluation requests pertaining to installed fuses that were a different size than specified on design drawings.

For the past year, QC inspected for correct fuses during the performance of any routine maintenance in safety-related applications. PIR NP 91-0801 was initiated to determine the root causes of incorrect fuse installation. The root cause appears to be that the architect engineer failed to update applicable drawings for vendor equipment (vendor drawings) when a change to the equipment design occurred. Changes were reflected, however, on the applicable engineering drawings. It has been a practice for I&C personnel to rely on the vendor drawings. Immediate corrective actions taken require that I&C and electrical maintenance personnel check both the engineering drawings and vendor drawings prior to the performance of work. Any discrepancies will be referred to NPE, and QC will continue to inspect fuses during routine maintenance. The licensee is considering establishment of a fuse control program. Further inspection followup in this area will be tracked by an inspection followup item (482/9136-05).

Conclusions

The performance of maintenance activities was mixed. The replacement and repair of two relief valves were generally well performed; however, a poor radiological practice of leaning over a barrier for a contaminated area was identified by a health physics technician and observed by the inspector. An inadequate procedure resulted in internal damage of safety injection accumulator discharge isolation MOV. However, a mechanic noted that the MOV gear ratio did not agree with the design gear ratio. The root cause of a recurring problem associated with the TDAFW pump trip and throttle valve was identified. However, the problem with the valve cycling open and closed when the "open" pushbutton was pushed had occurred at least two other times. One of these occurrences was not explicitly identified. Numerous fuse control problems have been documented by QC personnel. The problem was attributed to out-of-date vendor drawings. Long-term corrective actions will be tracked as an inspection followup item.

7. REFUELING ACTIVITIES (60710)

The purpose of this inspection area was to ascertain whether refueling activities were being controlled and conducted as required by TS and approved procedures. The inspectors observed portions of fuel load from the fuel building, control room, and containment. Items inspected included:

o Fuel handling operations and other ongoing activities were performed in accordance with TS and approved procedures;

o Plant conditions were maintained as required by TS;

o Good housekeeping and loose object control were maintained in the refueling and spent fuel areas;

o Licensee staffing was in accordance with TS and approved procedures; and

o Periodic testing and verification of the operability of refueling related equipment and systems were performed as required by TS and approved procedures.

The following is a list of the major safety-related activities performed during this inspection period:

o Replaced Reactor Coolant Pump B motor;

o Performed maintenance on both DGs;

o Completed removal of RCS bypass manifolds and installed new resistance temperature detectors (RTDs);

- o Performed maintenance on 4160 volt Bus NB01;
- o Installed new containment cooler coils;
- o Installed permanent reactor cavity seal;
- o Performed sludge lancing of the SGs;
- o Performed eddy current testing on SGs A and C and removed Inconel 600 plugs and replugged as required; and
- o Performed static VOTES testing on MOVs.

Conclusions

The outage was carefully controlled. However, the outage was extended because of a failed fuel rod, delays encountered during cleaning of the CCW heat exchangers and manway repairs, difficulties in trying to stop the leakby of the new boron injection tank inlet bypass valves, and additional time to resolve significant NRC and licensee identified MOV deficiencies.

8. PLANT STARTUP FROM REFUELING (71711)

The purpose of this inspection was to ascertain whether systems maintained or tested during Refuel Outage V were returned to an operable status before plant startup and to determine whether plant startup, approach to criticality, and core physics tests following the refueling outage were conducted in accordance with approved procedures.

The inspector observed the transition from Mode 4 to Mode 3 which was performed on January 6, 1992. Mode 3 was reached at 3:59 a.m. The mode change was performed in accordance with Procedure GEN 00-002, Revision 17, "Cold Shutdown To Hot Standby."

On January 12, the inspector observed control room operator and reactor engineer activities during the approach to criticality. The approach to criticality was controlled by Procedure RXE 01-002, Revision 3, "Reload Low Power Physics Testing." The inspector determined that personnel followed the procedure, as demonstrated by determining the inverse count rate ratio, monitoring the RCS temperature, monitoring boron concentration in the RCS and pressurizer as specified, and monitoring reactor power to assure that the point of adding heat was not achieved. After criticality was achieved, low power physics testing occurred. The physics tests validated the nuclear design operating parameters for the cycle.

The inspector reviewed the remainder of the low power physics test procedure and the test data. The areas reviewed included: boron endpoint determination, isothermal temperature coefficient measurement, and bank worth measurements (rod swap method). The procedure was well written and easy to follow. Additionally, the inspector verified that the resistance temperature detector (RTD) calibration was performed in accordance with

Procedure STS RE-014, Revision 2, "Calibration of Wide and Narrow Range RTDs." Three RTDs that failed to meet the acceptance criteria were recalibrated in accordance with the procedure.

On January 12, 1992, during the manual withdrawal of the control banks (CBs) in overlap while approaching criticality, the operators received a rod control urgent failure alarm, with CB A at 116 steps and CB B at 1 step. When the problem was investigated, the licensee determined that all lift coil disconnect switches except for Rod K-14 on CB B were disconnected. The operators reinserted the CB A control rods to 113 steps to reset the logic and to ensure the proper overlap occurred upon withdrawal. The licensee personnel reconnected the CB B lift coil disconnect switches, verified all other control rod disconnect switches were in the correct position, and reset the control rod urgent failure alarm. As the operators recommenced control rod withdrawal, they verified correct overlap between CBs A and B.

The licensee determined that the lift coil disconnect switches were not properly restored for the affected rods as required by Step 5.4.22.10 of Procedure STS RE-007, Revision 5, "Rod Drop Time Measurement," that was performed on January 10, 1992. The licensee initiated a PIR to document the above deficiency. This event also appears to have been caused by inattention to detail. This is the second example of a violation of TS 6.8.1.a (482/9136-02).

Conclusion

Overall, the plant startup, approach to criticality, and core physics tests were well performed. All data met the design specifications which verified the core design. A control rod urgent failure alarm resulted during rod withdrawal because control rod drive mechanism lift coil disconnect switches were left disconnected as the result of a failure to follow an approved procedure. This event appears to have been caused by inattention to detail.

9. EXIT MEETING

The inspector met with licensee personnel denoted in paragraph 1 on January 27, 1992. The inspector summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

Acronym and Initialism List

amp	ampere
CCP	centrifugal charging pump
CCW	component cooling water
CB	control bank
DG	diesel generator
ECCS	emergency core cooling system
EER	engineering evaluation request
EGM	electric governor mechanism
ESW	essential service water
gpm	gallons per minute
HP	health physics
I&C	instrumentation and control
IRM	intermediate range monitor
LCO	limiting conditions for operation
LER	licensee event report
MOV	motor operated valve
NPE	nuclear plant engineering
NRC	Nuclear Regulatory Commission
PDP	positive displacement pump
PIR	performance improvement request
psig	pounds per square inch gage
QC	quality control
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RTD	resistance temperature detectors
SG	steam generator
SI	safety injection
STN	surveillance nontechnical specification
STS	surveillance technical specification
TDAFW	turbine driven auxiliary feedwater
TS	Technical Specification
VOTES	Valve Operation Test and Evaluation System
WR	work request