APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-298/91-04 Operating License: DPR-46

Docket: 50-298

Licensee: Nebraska Public Power District (NPPD)
P.O. Box 499
Columbus, Nebraska 68602-0499

Facility Name: Cooper Nuclear Station (CNS)

Inspection At: CNS, Nemaha County, Nebraska

Inspection Conducted: February 20 through April 2, 1991

Inspectors: W. R. Bennett, Senior Resident Inspector
G. A. Pick, Resident Inspector

Approved: P. H. Harrell, Chief, Project Section C 4-9-91 Date

Inspection Summary

Inspection Conducted February 20 through April 2, 1991 (Report 50-298/91-04)

Areas Inspected: Routine, unannounced inspection of followup of events, operational safety verification, maintenance and surveillance observations, installation and testing of modifications, and onsite followup of written reports.

Results:

- The licensee demonstrated a proactive stance concerning the shutdown contingency plan and work in the switchyard (paragraphs 3.a and 7).
- The licensee's response and investigation into potentially inoperable snubbers was prompt and conservative (paragraph 5.c).
- Personnel performed radiological protection and security activities in a good manner (paragraphs 4.d and 4.e).
- Initiatives to place management personnel in operator training classes should increase the overall effectiveness of site management (paragraph 4.d).
- Quality of maintenance procedures (MP) improved and special instructions provided detailed guidance (paragraph 5).

- Personnel conducted surveillance activities in accordance with procedures and followed proper radiological practices (paragraphs 6.a, 6.c, and 6.d).

- During turbine testing, good communications were maintained and extra precautions were taken to prevent an inadvertent turbine trip (paragraph 6.c).

DETAILS

1. Persons Contacted

Principal Licensee Employees

J. M. Meacham, Division Manager of Nuclear Operations
E. M. Mace, Senior Manager of Staff Support
R. L. Gardner, Senior Manager of Operations
R. L. Beilke, Radiological Manager
J. R. Flaherty, Engineering Manager
M. R. Ward, Acting Outage and Modifications Manager
G. E. Smith, Quality Assurance Manager
R. Brungart, Operations Manager
M. E. Unruh, Maintenance Manager
M. A. Dean, Licensing and Safety Supervisor
L. E. Bray, Regulatory Compliance Specialist

Those personnel listed above attended the exit interview conducted on April 2, 1991. The inspectors also contacted other personnel.

2. Plant Status

The plant operated at essentially 100 percent power until March 23, 1991, when the plant was shut down to repair a leak on a feedwater check valve. The plant was taken critical on March 27, synchronized to the grid on March 28, and operated at essentially 100 percent power for the remainder of this inspection period.

3. Followup of Events (93702)

a. Plant Shutdown

On March 22, 1991, the licensee commenced decreasing power to make a drywell entry and perform minor maintenance. Prior to the power decrease, the licensee prepared a schedule that included a contingency plan for cold shutdown if problems were found in the drywell. On March 23 the licensee discovered a leak from the hinge pin of the Loop B outboard feedwater check valve located in the steam tunnel. The licensee decided to perform a normal reactor shutdown and cooldown to repair the leak. The licensee scrammed the reactor from approximately 20 percent power on March 23. The shutdown and cooldown were performed in a controlled manner with no problems identified.

b. Drywell Noise

On March 24, 1991, personnel in the drywell reported hearing a loud noise. Shortly afterward, control room operators noted a slight reactor water level decrease and recirculation and core flow

fluctuations. The licensee subsequently performed an inspection of the drywell to verify that no damage occurred and to identify the source of the loud noise. The inspection revealed that no damage occurred; however, indications that feedwater piping had moved were identified. The licensee's investigation determined that the source of the noise was a water hammer produced by a vacuum created in the feedwater piping during draining. The vacuum was created due to a combination of valve leakage from the reactor to the feedwater system and the large difference in elevations in the feedwater system. During the draining operations, the operator opened the low-point drain without opening a high-point vent. This caused a vacuum to be formed at the high point in the system. The leaking valve from the reactor caused an increase in saturation temperature and pressure of the water in the system. The pressure at the high point of the system decreased below saturation pressure causing the water to flash and form a saturated vapor void. The subsequent collapse of this void, when the vacuum was reduced, caused a water surge leading to the water-hammer event.

The licensee subsequently performed an extensive walkdown of the drywell, torus area, steam tunnel, and feed pump rooms to identify any equipment damage that might have occurred. No adverse effects from this event were noted. The licensee tested mechanical snubbers in the vicinity of the water hammer area and determined that they moved freely. During plant startup, the licensee inspected the applicable portions of the feedwater system. No leaks were found. The licensee was evaluating the method used for draining systems to prevent any future similar occurrences.

c. Steam Leak

On March 28, during plant startup at approximately 800 pounds pressure, the licensee discovered steam leaking from a crack approximately 3/8-inch long. The crack was located on the high pressure coolant injection (HPCI) steam supply drain line in the steam tunnel. The licensee reduced reactor pressure and performed a weld repair and leak check on the line.

The licensee's preliminary evaluation indicated that the crack was caused by flow-induced erosion. The licensee walked down additional steam lines and did not identify additional problems.

This was the second identified steam leak on this piping run in approximately 6 months. The licensee was evaluating the possibility of fitting and/or pipe replacement during the next refueling outage, currently scheduled for October 1991.

Conclusions

The licensee properly evaluated and responded to a water-hammer event that occurred during feed system draining. The licensee was proactive in their

preparations for a potential required shutdown and took conservative actions when the shutdown was necessitated.

4. Operational Safety Verification (71707)

a. Control Room Observations

The inspectors observed operational activities throughout this inspection period. Proper control room staffing was maintained and control room professionalism and decorum were observed. Discussions with operators determined that they were cognizant of plant status and aware of the reason for each lit annunciator. The inspectors observed selected shift turnover meetings and noted that information concerning plant status and planned evolutions was properly communicated to the oncoming operators. The inspectors routinely verified, by visual inspection of emergency core cooling system valve indications, that the systems were maintained in a standby condition. The inspectors observed that all required limiting conditions for operation were properly documented and tracked by the control room staff.

b. Power Decrease to Conduct Surveillance Tests and Make Control Rod Adjustments

On March 3, 1991, the inspector observed operator actions during main turbine testing and control rod scram time testing (see paragraph 6.e). The operators decreased reactor power to 70 percent prior to beginning the surveillance testing. After operators completed the tests, reactor engineers provided information to the operators for making control rod adjustments. Control rod withdrawals were made to raise the rod line, giving the operators some margin to adjust power with recirculation flow.

The operators withdrew the control rods in accordance with the rod pull sheet, while reducing recirculation flow to maintain reactor power at 70 percent. After completion of the control rod adjustments an On Demand (OD)-1, "Whole Core Local Power Range Monitor (LPRM) Calibration and BASE Distribution," was performed. The OD-1 updates the BASE distribution data file and determines LPRM detector calibration constants so the LPRMs may be adjusted to accurately reflect the core power distribution.

During the reactivity changes, reactor engineering oversight was evident. The inspector observed excellent cooperation between engineering and operators during control rod adjustments.

c. Nonqualified Flow Switch Wires

On February 27, 1991, the manufacturer of the licensee's containment hydrogen/oxygen analyzer notified the licensee that the flow switches used to detect low-flow conditions may not be environmentally

qualified. The manufacturer stated that some of the flow switches were manufactured with nonqualifed teflon-insulated wires and some with qualified Tefzel-insulated wires. On February 28 the system engineer and the environmental qualification program engineer determined that the installed switches had the nonqualified teflon-insulated wires. An operability analysis was performed that demonstrated that the wires would remain intact and would perform their intended safety function under the expected design basis radiation levels.

Although the operability analysis determined the analyzers to be operable, the licensee prepared a justification for continued operation (JCO) as required by plant procedures. The licensee implemented a procedure change for overriding the low-flow alarm if needed. The JCO remained in effect until March 22 when instrument and control (I&C) technicians installed flow switches with qualified wires.

d. Radiological Protection Observations

The inspectors verified that selected activities of the licensee's radiological protection program were properly implemented. Radiation and contaminated areas were properly posted and controlled. Health physics (HP) personnel were observed touring work areas to ensure that the radiological protection program was properly implemented. Radiation work permits contained appropriate information to ensure that work could be performed in a safe and controlled manner. During power changes, HP technicians performed required surveys to ensure that radiation areas were properly posted and maintained.

On March 6 and 7 the inspector monitored HP technicians as they surveyed scaffolding and other reactor building roofing equipment. The radiological surveys ensured that the materials were not contaminated prior to removal from the protected area (PA).

During the period March 1991 to April 1992, the Radiological Manager will be in hot-license training. At the end of the training, he will take a licensee administered examination and will become certified. In his absence, the Radiological Support and HP Supervisors will alternate as radiological manager for 8 and 5 months, respectively. These two individuals meet or exceed the requirements specified in the Technical Specifications (TS) for the position of Radiological Manager. Additionally, the Senior Manager, Technical Support Services is attending shift technical advisor training.

e. Security Observations

The inspectors observed security personnel perform their duties of vehicle, personnel, and package searches. Vehicles were properly authorized and controlled or escorted within the PA. Personnel access was observed to be controlled in accordance with established

procedures. The PA barrier was adequately illuminated and the isolation zones were free of transient materials.

On March 19 dense fog was present at the CNS. The inspector observed that extra security guards were posted as compensatory measures. The security guards were aware of their responsibilities while compensatory measures were in effect.

f. Plant Startup

On March 27 and 28, 1991, the inspector observed portions of a plant startup. The startup was performed in a controlled, conservative manner. A second licensed operator or qualified reactor engineer verified proper rod withdrawal sequence. The reactor was declared critical on March 27. On March 28, while at 800 pounds reactor pressure, the licensee discovered a steam leak on the HPCI steam supply drain line in the steam tunnel (see paragraph 3.c). Reactor pressure was reduced to 300 pounds while repairs were made. The turbine was synchronized to the grid on March 28. No problems were identified.

Conclusions

The power decrease, surveillance testing, and control rod adjustments were well implemented. Management initiatives to increase operational knowledge level of site managers should increase management effectiveness. Personnel performed radiological protection and security activities in a good manner.

5. Maintenance Observations (62703)

a. Reactor Water Cleanup (RWCU) Pump Repairs

On February 26, 1991, the inspector observed mechanics reassemble RWCU Pump A in accordance with plant procedures and special instructions. The pump was being repaired because the inboard pump-to-motor coupling bearing failed. The mechanics determined that a manufacturing defect (the oil ports were not aligned) prevented lubricating oil from returning to the reservoir.

After installing the pump, the mechanics could not rotate the impeller. After disassembly of the pump, the mechanics identified another manufacturing defect. The keyway was tapered instead of square, which caused binding of the impeller. The keyway was machined, the pump reinstalled, and postmaintenance testing satisfactorily completed. No problems were identified.

The inspector noted that the mechanics properly implemented the licensee's quality control program, at the specified points, through the peer-review program.

b. Service Water Booster Pump (SWBP) Rebuild

On February 27 and 28, 1991, the inspector observed mechanics install mechanical seals and reassemble a new spare residual heat removal (RHR) SWBP. The activity was conducted in accordance with MP 7.2.14, "RHR SWBP Overhaul and Replacement," Revision 13. The procedure specified steps for centering the rotating assembly, for setting the bearing and wear ring clearances, and for adjusting the thrust bearing end play. The mechanics referred to the procedure as needed. Torque wrenches were properly calibrated prior to use and verified as being calibrated after use. Discussions with the mechanics about the work to be accomplished indicated that they were aware of the work scope, tools needed, and critical measurements.

The inspector noted that the critical measurements taken by one mechanic were independently verified by another mechanic, as required by the licensee's peer-review program.

c. Hydraulic Snubber Inspections

On March 5, 1991, the inspector observed mechanics conduct visual inspections on four hydraulic snubbers. Discussions with the engineer responsible for the snubber inspection program indicated that accessible snubbers were being inspected on an increased frequency as part of a nonconformance report (NCR) corrective action commitment. The licensee initiated the NCR after identifying a hydraulic snubber with a fluid leak.

The mechanics inspected the snubbers in accordance with MP 7.2.34.1, "Snubber Inspection," Revision 3. The procedure provided detailed inspection criteria and identified critical inspection steps that could effect snubber operability. Snubbers with acceptable off-normal conditions were identified in an attachment.

Even though the mechanics were familiar with the visual inspection requirements, they reviewed the procedure prior to start of the work activity. Acceptable off-normal conditions and discrepancies identified during the mechanic's inspection were listed on the inspection data sheets. Good communication occurred between the mechanic conducting the inspection and the mechanic documenting the inspection results.

On March 7, during inspection of RHR Train B Snubbers S30A and S30B, the mechanics determined the pipe clamps to be bent due to a high impact compressive loading. Because of the bent pipe clamps, both sides of the snubber paddle touched the pipe clamp simultaneously. After engineering reviewed the condition of the clamps, the licensee declared the snubbers to be inoperable in accordance with TS.

On March 8 the onsite review committee approved a work item for replacement of the pipe clamps and hydraulic snubbers. The

committee's approval was required because the pipe clamps were not replaced with like-for-like clamps. The replacement clamps were 5/8-inch thick and manufactured of stronger material instead of 1/4-inch thick and stiffened by gussets.

The inspector's review of the work item package determined that the special instructions were thorough and complete. Proper quality control steps were specified and required work travelers were attached. TS 4.6.H.2 requires "For the snubber(s) found inoperable, an engineering evaluation shall be performed to determine the need for further action or testing on affected components." The licensee's evaluation stated that the most probable root cause was an air bubble that did not get properly vented (paragraph 3.b). The inspector determined that the evaluation was adequate because it addressed the most probable root cause in a logical, practical manner. Additionally, the licensee plans to test the snubbers to verify that they are operable.

d. Condensate Filter/Demineralizer Flow Loop Calibration

On March 12, 1991, the inspector observed I&C technicians implement Preventative Maintenance (PM) Item 01302. The nonsafety-related PM required the verification of correct flow indications on the condensate filter/demineralizer gauge and recorder.

The PM was implemented using skill-of-the-craft and a data sheet that listed required pressures. The test equipment was properly connected and within calibration. Discussions with the technicians indicated that they selected the test instruments based on the required input pressures and output values.

Conclusions

The licensee's response to and investigation of the potentially inoperable snubbers were prompt and conservative. Maintenance procedure quality had improved and special instructions provided detailed guidance.

6. Surveillance Observations (61726)

a. Testing of the Reactor Protection System (RPS) Pressure Switches

On February 25, 1991, the inspector observed I&C technicians perform the monthly functional test of the pressure switches that sense drywell pressure and initiate a reactor scram when the pressure exceeds 2 psig. The test was implemented in accordance with Surveillance Procedure (SP) 6.1.10, "RPS Primary Containment High Pressure Calibration and Functional/Functional Test," Revision 16.

The I&C technicians properly removed and returned the switches to service. Test instruments utilized were within calibration. Excellent communications were maintained during the test performance.

b. LPRM Calibration

On February 25, 1991, the inspector observed licensed operators perform OD-1. OD-1 calibrates the LPRMs so they will more accurately reflect the core power distribution. After OD-1 was completed, operators verified that the calibrated LPRM readings agreed with the actual measured power levels. The operators maintained excellent communications.

c. Automatic Depressurization System (ADS) Water Level Calibration

On February 27, 1991, the inspector reviewed I&C activities related to performance of SP 6.2.2.2.1, "ADS Water Level Calibration and Functional/Functional Test," Revision 24. These ADS switches provide a permissive signal for automatic blowdown timer actuation.

While returning the ADS Train B level switch to service, the I&C technician observed that the process instrument would not respond when he turned the pressurizing valve. The pressurizing valve is parallel to the isolation valve and slowly pressurizes the instrument to minimize sensing line perturbations. When the technician isolated the process instrument, the pressurizing valve tip became wedged in the valve seat and broke from the stem. The shift supervisor was notified of the situation and gave verbal approval for completing the surveillance. To compensate for the failed valve, the technician opened the isolation valve slowly.

Subsequently, the technician prepared a temporary procedure change to accurately reflect the method of removing and returning the instrument to service. During the maintenance outage, I&C technicians replaced the pressurizing valve and the temporary procedure change was deleted.

The inspector reviewed the test procedure and test results to verify the adequacy of the procedure and that the results met the acceptance criteria. No problems were noted.

d. Low-Low Water Level Instrument Functional Test

On February 28, 1991, the inspector observed I&C technicians test differential pressure switches that actuate at the low-low reactor vessel level setpoint. When the switches actuate, signals are sent to the alternate rod injection (ARI), anticipated transient without scram (ATWS), recirculation pump trip (RPT), and primary containment isolation system (PCIS) logic circuits. The functional test was conducted in accordance with SP 6.2.1.7, "ARI/ATWS/RPT and PCIS Reactor Low-Low Water Level Calibration and Functional Test," Revision 26.

The technician was familiar with the procedure precautions and limitations. Proper radiological controls were utilized and proper communications were established.

e. Main Turbine Testing

On March 3, 1991, the inspector observed operators perform the following turbine protection SPs:

- 6.1.7, "Main Turbine Stop Valve Closure and Steam Valves Functional Test," Revision 18. This surveillance verified proper valve operation and verified that a half-scram occurred when each valve closed.

- 6.4.8.2.2, "Main Turbine Lube Oil Pumps Functional Test," Revision 10. This surveillance verified that the backup lube oil pumps would automatically start on low pressure.

- 6.4.8.2.3, "Main Turbine Trip Functional Test," Revision 14. This surveillance verified that four separate trip functions actuated the overspeed trip valve.

During performance of the tests, continuous communications were maintained between the test performers and the control room. Proper radiological practices were followed. Extra precautions were taken during performance of SP 6.4.8.2.3 because of the potential for scramming the reactor. Prior to performance of SP 6.4.8.2.3, the licensed operator in charge conducted a pretest briefing to familiarize the station operators with the test sequence. The turbine bearing trip pressure switch actuated beyond the acceptable range. A work item was written to calibrate the pressure instrument. The work item was completed during the plant shutdown on March 22.

The inspector noted that the procedures used for test performance were satisfactory. The inspector also noted that the test results were independently reviewed by licensee personnel and found to be acceptable.

f. Scram Time Testing

On March 3, 1991, the inspector observed operators perform control rod scram time testing in accordance with Nuclear Performance Procedure 10.9, "Control Rod Scram Time Evaluation," Revision 19. This test was performed on 10 percent of the control rods to verify they met the scram time requirements listed in the TS.

All of the selected rods met the scram time criteria; however, one control rod was slow enough to require conducting a 2x2 rod array check as specified in TS. The rod array check verifies that the average value of the arrayed control rods met the scram time. No problems were identified.

Conclusions

Personnel conducted surveillance activities in accordance with procedures and followed proper radiological practices. During turbine testing, good communications were maintained and extra precautions were taken to prevent an inadvertent turbine trip.

7. Installation and Testing of Modifications (37828)

The licensee informed the inspector that work would be performed in the switchyard soon after approval of Design Change (DC) 90-305 "MINT Project Modification." The Missouri, Iowa, Nebraska Transmission (MINT) Project will connect grids in those states to provide more options for power distribution. The inspector asked if any extra precautions would be taken while working in the switchyard in light of recent industry problems with inadvertent losses of offsite power. The licensee provided a draft CNS Policy Directive that was being reviewed by Station Operations Review Committee (SORC) members. The inspector attended SORC Meeting 91-016, on March 20, 1991, where DC 90-305 was discussed. The SORC decided that the directive would be approved and added as a prerequisite to the DC. The inspector attended SORC Meeting 91-018, on March 25, where DC 90-305 was approved.

The importance of shutdown events to the NRC was emphasized by a letter from the Director, Office of Nuclear Reactor Regulation, to utilities. CNS demonstrated a proactive stance concerning industry events and had taken appropriate action prior to the issuance of this letter.

8. Onsite Followup of Written Reports (92700)

(Closed) Licensee Event Report (LER) 90-001 was reviewed to determine that corrective actions were accomplished and that actions were taken to prevent recurrence.

This LER concerned an HPCI isolation during performance of surveillance testing. The isolation occurred when the technician connected a multimeter to the wrong terminals. It was determined that the terminal wires were correctly labeled; however, specific terminal designators were not clearly specified in the procedure.

The licensee restored HPCI to service and completed surveillance testing. In addition, a procedure change was implemented upgrading the affected procedure and similar procedures were reviewed and upgraded.

The inspector reviewed the licensee's corrective actions and determined them to be appropriate.

9. Exit Interview

An exit meeting was conducted on April 2, 1991, with licensee representatives identified in paragraph 1. During this interview, the

inspectors reviewed the scope and findings of the inspection. Other meetings between the inspectors and licensee management were held periodically during the inspection period to discuss identified concerns. During the exit meeting, the licensee did not identify as proprietary, any information provided to, or reviewed by, the inspectors.