APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-285/90-39 Operating License: DPR-40

Docket: 50-285

Licensee: Omaha Public Power District (OPPD)
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

Facility Name: Fort Calhoun Station (FCS)

Inspection At: FCS, Blair, Nebraska

Inspection Conducted: October 23 through December 4, 1990

Inspectors: R. Mullikin. Senior Resident Inspector
T. Reis, Resident Inspector
A. Singh, Reactor Inspector
R. Azua, Project Engineer

Approved: P. H. Harrell, Chief, Project Section C 12-7-90
Date

Inspection Summary

Inspection Conducted October 23 through December 4, 1990 (Report 50-285/90-39)

Areas Inspected: Routine, unannounced inspection of onsite followup of events, operational safety verification, maintenance observations, review of previously identified items, licensee event report followup, review of cold weather preparations, and review of containment integrated leak rate test results.

Results:

- The licensee manually tripped the plant on November 19, 1990, due to decreasing instrument air (IA) pressure and steam generator level caused by a failure of a joint on the turbine building IA header. The shift supervisor's decision to manually trip the plant demonstrated a conservative approach to safety. Details of the event are provided in paragraph 3.a.

- The licensee was unsuccessful in determining the source of an increase in unidentified reactor coolant system leakage (paragraph 3.b).

- The licensee appears to exhibit good attention to detail in the performance of routine preventive maintenance activities (paragraph 5).

9012130114 901207
PDR ADOCK 05000285
Q PDC

- The licensee continues to be responsive to inspection findings and events by taking proper corrective actions to prevent recurrence (paragraphs 6 and 7).

  The licensee's activities associated with cold weather preparations were completed before the advent of cold weather (paragraph 8).

- The containment integrated leak rate test results were found to meet regulatory requirements (paragraph 9).

DETAILS

1. Persons Contacted

M. Bare, System Engineer
M. Core, Supervisor, Maintenance
S. Gambhir, Division Manager, Production Engineering
*J. Gasper, Acting Division Manager, Nuclear Operations
*R. Jaworski, Manager, Station Engineering
*B. Kindred, Special Projects/Performance Specialist
L. Kusek, Manager, Nuclear Safety Review Group
*D. Matthews, Supervisor, Station Licensing
*W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Manager, Fort Calhoun Station
A. Richard, Assistant Manager, Fort Calhoun Station
J. Sefick, Manager, Security Services
C. Simmons, Station Licensing Engineer
*S. Swearngin, Member, Nuclear Safety Review Group
D. Trausch, Supervisor, Operations

The inspector also contacted additional personnel.

*Denotes attendance at the monthly exit interview.

2. Plant Status

a. The FCS operated at 100 percent power from the beginning of this inspection period until November 19, 1990, when the reactor was manually tripped. The reactor was tripped due to decreasing IA pressure and steam generator level caused by a catastrophic failure of a sil-brazed joint in the turbine building IA header. The line was repaired and a modification made to support all other large line IA connections which will keep the joints "seated" in the event of failure of the brazing.

The plant achieved criticality on November 21, 1990. Full power was achieved on November 22, 1990, and maintained through the end of this inspection period.

b. The licensee, during this inspection period, announced the decision to inspect the reactor vessel thermal shield and its support system during the 1991 refueling outage scheduled to begin in September 1991. The licensee had planned to perform this inspection during the 10-year inservice inspection scheduled for the 1993 refueling outage.

Thermal shield support degradation is detectable as frequency peak shifts in the spectra of the incore detector neutron noise signals. Combustion Engineering has interpreted changes in the FCS neutron noise data to be indicative of loosening of the thermal shield positioning pins. The licensee has determined that there would not be a safety concern even if the thermal shield was to separate from the core support barrel.

3. Onsite Followup of Events (93702)

a. On November 19, 1990, at 4:29 p.m. (CST), the FCS was manually tripped from 100 percent power due to a transient involving the degradation of the IA system. Operations had entered Procedure AOP-17, "Loss of Instrument Air," and manually tripped the reactor with narrow-range steam generator level at 40 percent and falling. The steam generator low-level trip setpoint is 32 percent and normal operating range is 65-70 percent. IA pressure dropped from a nominal 100 psig to approximately 70 psig in less than 1 minute. Corresponding to the drop in IA pressure was a slight drop in the feedwater header pressure (20-60 psig).

The control room received a low IA pressure alarm at 4:23 p.m. and dispatched operators to search for the leak. Simultaneously, the loud noise, created by what was later found to be an IA header rupture, made all plant personnel aware of an anomaly. The inspector witnessed all available management, engineering, and quality control personnel who were in the power block at the time, search for the cause of the anomaly by walking down the steam and air systems.

It was found that a sil-brazed joint on the 2-inch IA ring header for the turbine building had failed. At approximately 4:33 p.m., manual ball valves on each side of the leak were shut and the leak was isolated.

The equipment affected by the isolation of a portion of the header was nonsafety-related but did affect steam dump and bypass control, condenser hotwell level control, and condenser vacuum.

The decrease in steam generator header pressure and steam generator level were attributed to a reduction in flow and pressure from the feedwater pumps. The reduction in flow was apparently caused by the condensate recirculation control valve (FCV-1172) failing open, which is served by an air riser affected by the break. The opening of the recirculation valve diverted flow from the feedwater pumps back to the condenser hotwell.

Compounding this reduction in flow was the fact that the feedwater regulating valves failed in the "as is" position when IA pressure decreased to approximately 75 psig. This occurred as designed in order to maintain the same flow that would have existed prior to the loss of air. However, due to the diverted feedwater flow, the feedwater regulating valves sensed the steam/feedwater flow mismatch and opened approximately 8 percent prior to failing "as is."

After the reactor trip, steam generator levels underwent the normal posttrip shrink, then immediately started increasing at a rapid rate since the feedwater regulating valves had failed "as is" with two feedwater pumps still in operation. Prior to isolating the feedwater regulating valves by shutting their corresponding motor-operated valves (HCV-1103 and 1104), steam generator levels had peaked at 100 percent on the narrow-range scale. Level was maintained by placing the motor-driven auxiliary feedwater pump (FW-6) into service. The excessive feeding caused reactor coolant system (RCS) pressure and inventory to decrease but the RCS was maintained within its pressure-temperature limits as specified by Technical Specification (TS) 1.1. Safeguards actuation did not occur and no safety or relief valves lifted on the primary or secondary systems.

After the trip, the inspector observed operations appropriately enter Procedure EOP-00, "Standard Post Trip Actions," and the emergency plan. Management and operations personnel reviewed the Emergency Plan Implementing Procedure OSC-1 and considered a Notification of Unusual Event (NOUE) warranted based on [illegible] Action Level (EAL) 11.6, which stated that "Plant Conditions Warrant Increased Awareness by Plant Staff or Government Authorities." The EAL for IA degradation, 11.5, required that a NOUE be declared if IA pressure drops to less than 50 psig. The lowest IA pressure was measured at 70 psig. However, since the leak was isolated and the header repressurized prior to determining the appropriate EAL, the NOUE was not declared. The states of Nebraska and Iowa were notified as a courtesy. A 1-hour report, pursuant to 10 CFR Part 50.72(a)(i), was made to the NRC operations center at 5:29 p.m. (CST). The inspector was on site during the transient. Initially, condenser vacuum was maintained and cooldown progressed with steam bypass to the condenser. As operations noted that condenser vacuum was gradually decreasing, they manually switched to the atmospheric dump valves.

The inspectors reviewed the licensee's posttrip review. Based on the review, it appeared that all safety systems functioned as designed. There were no anomalies found that would have precluded restart of the reactor. To address the problem of the failure of the IA header, the licensee installed a modification on all similar sil-brazed joints in the turbine building IA header which will keep the joints "seated" in the event of failure of the brazing. The licensee had previously installed this modification on the auxiliary building header.

b. Prior to the shutdown, the plant was experiencing an increase in unidentified RCS leakage. This leakage had increased from approximately 0.1 to 0.4 gpm. This was well below the TS-allowed limit of 1.0 gpm.

The licensee performed containment entries to search for leakage, but due to ALARA concerns, not all areas could be inspected at full power. On the same day as the forced outage of the plant, the licensee was considering reducing reactor power to inspect other areas in containment.

While the plant was in Mode 3, the licensee discovered, during a containment entry, that the containment spray lines were full of water. Leakage past a low-pressure safety injection isolation valve and the containment spray header isolation valves (HCV-344 and -345) were suspected as the source. HCV-344 and -345 are ball valves and the licensee found that both had some overtravel and were leaking. The valves were properly aligned and the plant was restarted.

However, the unidentified RCS leakage continued after startup. The licensee has organized a group consisting of three system engineers, an assistant plant manager, and a senior reactor operator to locate the source of the leakage. This work was ongoing at the end of this inspection period. The inspector will report the licensee's findings and corrective action when completed.

4. Operational Safety Verification (71707)

The inspectors conducted reviews and observations of selected activities to verify that facility operations were performed in compliance with the appropriate regulatory requirements.

On November 5, 1990, the inspector received copies of the latest version of NRC Form 3. The inspector reviewed the postings at the entrances of the protected area and at a bulletin board in the training center. All postings were found to be the current version. In addition, the bulletin boards were also verified against the requirements of 10 CFR Part 21.6 and found to be satisfactory.

In addition, the inspectors routinely toured the control room to observe the operations staff in the performance of their duties. The inspectors noted that access controls were enforced, control room staffing maintained, and operations management was in the control room on a daily basis. When questioned, operators were cognizant of plant status and the reasons for lit annunciators.

5. Maintenance Observations (62703)

The inspectors observed selected station maintenance activities on safety-related systems and components.

a. On November 16, 1990, the inspector witnessed preventive maintenance (PM) activities related to the circuits required for fast transfer capability of the 4160-volt bus. Voltages were recorded to verify the ability of the open breakers to close on the required signal. This evolution was performed under PM Order (PMO) 9093277 using Procedure PM-EE-7-1.

b. On November 16, 1990, the inspector witnessed the PM for the DC bus ground check. This work was completed under PMO 9093274.

c. On November 19, 1990, the inspector witnessed a portion of the inspection and insulation resistance testing of Breaker SI-2B-M, which is the supply breaker to High-Pressure Safety Injection Pump SI-2B. The activity was performed under Work Plan WP001648 using Procedure EM-PM-EX-1000.

The inspector observed, in all activities, good attention to detail and adherence to procedural requirements.

6. Review of Previously Identified Items (92701 and 92702)

a. (Closed) Violation 285/9002-04: Inadequate corrective action on operability of raw water (RW) pump discharge check valves

This violation was cited for the licensee's failure to perform ASME Section XI testing of the RW pump discharge check valves.

Safety Analysis for Operability (SAO) 89-10, "Raw Water System Check Valve RW-125," was developed by the licensee to justify continued safe operation of the plant with the internals of Check Valve RW-125 removed. A basic premise of the analysis was that back leakage through an alternate discharge check valve (RW-127) would be tested. However, the licensee erroneously suspended the Section XI testing, so the back leakage through RW-127 was unknown for a period of 1 year. Subsequent testing supported the SAO assumptions. Therefore, the plant did not operate in an unanalyzed condition.

As corrective action to this event, the licensee replaced the degraded RW pump discharge check valves and subsequently resumed Section XI testing. SAO 89-10 has been closed. The licensee examined all outstanding SAOs to determine if any similar assumptions applied. None were found and the licensee concluded this was an isolated case and not a programmatic breakdown.

As long-term corrective action the licensee revised Procedure NOD-QP-22, "Safety Analysis for Operability." The revisions included:

- Instructions to indicate that, in the event SAO requirements are more restrictive than those of an existing approved procedure, a caution statement must be added to the affected procedure indicating this fact.
- A section was added to the procedure requiring the preparer to state actions that are required to maintain the validity of the SAO.

The inspector reviewed the short- and long-term corrective actions taken by the licensee. The corrective and preventive measures taken appear adequate to prevent recurrence of the situation.

b. (Closed) Unresolved Item 285/8938-02: Nonconservative value of the radial peaking factor

This item was the subject of a license event report (LER 89-021) submitted subsequent to the issuance of this unresolved item. Thus, this item will be closed and followup performed as part of the review of the LER.

7. Licensee Event Report (LER) Followup (92700)

The following event report was reviewed to determine that reportability requirements were fulfilled, corrective actions were accomplished, and actions were taken to prevent recurrence.

(Closed) LER 90-10 reported an automatic start signal received by Emergency Diesel Generator (EDG) 1 during the 1989-1990 refueling outage; however, the EDG did not actually start because it had not yet been returned to service from scheduled maintenance.

The primary cause of the inadvertent start signal was a lack of coordination of work activities during the outage. In parallel with inspection and maintenance of EDG 1, Bus 1A1 was deenergized and tagged out for scheduled maintenance. Bus 1A1 is nonvital but, per design, it provides an anticipatory start of EDG 1 when low voltage is present. This start signal is nonsafety-related and no credit was taken for it in the Updated Safety Analysis Report (USAR). During the simultaneous maintenance, the EDG 1 mode switch was placed in the "Off-Auto" mode so it could not receive its start signals.

At the time of the event, maintenance on EDG 1 had been completed and work was in progress to return the system to service. Surveillance Test MM-ST-DG-001 was the procedure controlling the inspection and testing of EDG 1. The test required that EDG 1 be started following inspection. In preparation for starting the diesel, operations were performing Procedure OI-DG-1, "Normal Operation Diesel Generator No. 1." This procedure required the alignment of the mode switch to the "Emergency Standby" position. Subsequently, due to the valid low-voltage signal present from Bus 1A1, the start signal was received and the EDG attempted to start but couldn't due to insufficient air pressure in the air-start accumulators.

As immediate corrective action, caution tags were put on the mode selector switches as reminders to verify that conditions that initiate an auto-start of the EDGs do not exist prior to changing the mode switch from the "Off-Autc" position.

As programmatic corrective action, the licensee revised Procedures OI-DG-1 and OI-DG-2 to include a caution statement for the operator to ensure that a diesel auto-start signal is not present before realigning the diesel for normal operation or testing. The revision included a list of the auto-start signals that will initiate a diesel start. Additionally, a step was added to verify starting air pressure prior to placing the mode switch in "Emergency Standby."

Surveillance Tests MM-ST-DG-0001 and MM-ST-DG-0002 were revised to include a step to ensure that applicable sections of Procedures OI-DG-1 and OI-DG-2, respectively, are performed prior to starting the affected diesel.

The inspector reviewed the procedure changes and considered that, if properly adhered to, the changes will prevent recurrence of this type of inadvertent start signal. This LER is considered closed.

8. Review of Cold Weather Preparations (71714)

The inspectors toured various plant areas and reviewed documentation to verify that the licensee had taken measures established by the PM program to ensure that systems affected by extreme cold weather were properly protected. The items observed and/or reviewed by the inspectors included:

- The freezing point of the plant emergency and fire water pump diesels had been tested to verify that an adequate amount of antifreeze was present in the cooling systems.
- The steam supply to the condensate storage tank had been initiated.
- The stop log used to divert the plant cooling water outflow from downstream to upstream of the intake structure was installed. The flow is diverted to prevent ice floes from clogging the intake structure grids.
- The ice deflector was in place to divert ice floes in the Missouri River away from the intake structure grids.

No problems were noted during this review.

9. Review of Containment Integrated Leak Rate Test (CILRT) Results (70323)

The inspector reviewed the CILRT results for the test completed on March 4, 1990. The purpose of this test was to demonstrate that containment leakage, under prescribed postaccident conditions, would not exceed allowable leakage specified in the USAR and TS.

The test was conducted in accordance with the requirements of 10 CFR Part 50, Appendix J, using the absolute method defined in ANSI N45.4-1972. Leakage rates were calculated using the mass point data method. The as-left, Type A and minimum pathway, Type B and C leakage rates were used to calculate the as-found CILRT leakage rates. The as-found and as-left leakage rates were calculated at the 95 percent upper confidence limit and were less than 75 percent of the maximum allowable leakage rates. The inspector verified these values by performing manual calculations.

All requirements of Appendix J to 10 CFR Part 50, the USAR, and the TS were satisfied.

10. Exit Interview

The inspectors met with Mr. J. Gasper (Acting Division Manager, Nuclear Operations) and other members of the licensee staff on December 4, 1990. The meeting attendees are listed in paragraph 1 of this inspection report. At this meeting, the inspectors summarized the scope of the inspection and the findings. During the exit meeting, the licensee did not identify, as proprietary, any information provided to, or reviewed by, the inspectors.