ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-17

License: DPR-46

Licensee: Nebraska Public Power District
1414 15th Street
Columbus, Nebraska

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: November 12 through December 23, 1995

Inspectors: M. H. Miller, Senior Resident Inspector
C. E. Skinner, Resident Inspector

Approved: Terrence Reis — 1-18-96
T. Reis, Acting Chief, Project Branch C — Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite review of events, operational safety verification, maintenance and surveillance observations, onsite engineering activities, plant support activities, followup - engineering, and in-office review of licensee event reports (LERs).

Results:

Operations

- Operations' immediate response to two brief losses of shutdown cooling, the first apparently caused by spurious actuation of a pressure switch, the second by improper maintenance, was thorough in that procedures were followed and relay positions and system configurations were verified before shutdown cooling was returned to service (Sections 2.1 and 2.2).

- Both the control room crew and outage scheduling organization improved in safety performance over the outage with respect to the identification of system vulnerabilities and interactions before accomplishment of maintenance and testing (Section 3.1).

- Refueling operations were well controlled by operations personnel (Section 3.3).

Maintenance\Surveillance

- An example of a violation was identified for not appropriately controlling maintenance activities, resulting in filling of an active reference leg, causing engineered safety feature (ESF) actuations and a loss of shutdown cooling (Section 2.2).

- A second example of a violation was identified for not controlling safety-related parts when incompatible fuel injectors were installed on Diesel Generator (DG) 2 (Section 4.5).

- A third example of a violation was identified when inadequate work instructions resulted in a jumper on the controls to a service water valve being installed too long, which ultimately resulted in a DG 1 trip on high bearing temperature (Section 5.3)

- Construction personnel involved in high pressure coolant injection (HPCI) vacuum breaker replacement and installation were conscientious and followed detailed drawings carefully (Section 4.1).

- Quality assurance (QA) identified multiple findings with respect to the control of DG overhaul maintenance and design changes. Problem identification by QA was strong; however, few problems were identified by the DG 18-month overhaul by maintenance technicians (Sections 4.2 - 4.4).

- A violation was identified when: the NRC identified that the torus closeout surveillance procedures did not require that foreign material exclusion (FME) logs be reconciled (Section 4.7), the NRC discovered drop lights, shims, and rad protection items in drywell downcomers (Section 4.6), and when foreign material was introduced into a main steam isolation valve (MSIV) via hoses used to provide flushing water (Section 4.8). Other FME problems were identified by the NRC and the licensee throughout the outage.

Engineering

- The NRC identified that, for the hydrostatic pressure surveillance procedure, engineering designated a valve of marginal rating to be opened in the event of a pressure spike, to prevent a challenge to a safety valve. The valve was rated to open under a maximum differential pressure of 1146 psid, only 18 pounds greater then the maximum allowed surveillance pressure and significantly less than the operable safety valve setpoint (Section 5.2).

- The licensee did not take into account the characteristics of adhesive used in the torus and the consequences of the adhesive failing during a design basis accident (Section 3.4).

- The evaluation of potential emergency core cooling system (ECCS) strainer clogging due to removal of the outer tape covering on reactor equipment cooling (REC) piping did not evaluate the exposed insulation characteristics and vulnerabilities under loss-of-coolant accident (LOCA) conditions and indicated that a tortuous path would be taken for the insulation to get to the strainers, although the path appeared to be direct (Section 6.3).

- The licensee identified inadequacies in both the licensee's and a valve vendor's design control and limiting component calculations for installed plant valves (Section 6.1).

- QA followup of valve vendor design control was very strong and involved timely audits of multiple valve vendors, which could affect design control for valves installed in the plant (Section 6.1).

Plant Support

- Health physics personnel identified that radioactive waste shipped to the plant had higher than allowable radiation readings at the container surface (Section 7).

Summary of Inspection Findings:

Open Items

- (Open) 298/9517-01: Violation: Failure to Control Foreign Material

- (Open) 298/9517-02: Violation: Inadequate Control of Maintenance and Testing Activities

- (Open) 298/9517-03: Unresolved Item: Valve Configuration Control

- (Open) 298/9514-01: Unresolved Item: Steam Tunnel Blowout Panel Incorrect Installation

Closed Items

- LER 93-027, Revision 0 (Section 9)
- LER 94-005, Revision 0 (Section 9)
- LER 94-006, Revision 1 (Section 9)
- LER 94-008, Revision 0 (Section 9)
- LER 94-010, Revision 1 (Section 9)
- LER 94-016, Revision 0 (Section 9)
- LER 94-016, Revision 1 (Section 9)
- LER 94-027, Revision 0 (Section 9)
- LER 94-027, Revision 1 (Section 9)
- LER 94-030, Revision 0 (Section 9)
- LER 94-031, Revision 0 (Section 9)

- LER 95-007, Revision 0 (Section 9)
- LER 95-007, Revision 1 (Section 9)
- LER 95-009, Revision 0 (Section 9)
- LER 95-015, Revision 0 (Section 9)
- LER 95-016, Revision 0 (Section 9)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

On October 14, 1995, the licensee began a scheduled refueling outage. Originally scheduled for 55 days, the refueling outage continued throughout the end of this inspection period, 15 days beyond schedule. At the close of this inspection period, the licensee was completing work and preparing for plant restart.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Loss of Shutdown Cooling

On December 9, 1995, shutdown cooling was lost for approximately 44 minutes. The reactor water level was greater than 60 inches (approximately 224 inches above active fuel, which allowed natural circulation to initiate to cool the core. The reactor temperature increased 3°F in the 44 minutes.

Residual heat removal (RHR) Pump A was used for shutdown cooling when the isolation occurred. The RHR shutdown cooling isolation valves closed, resulting in a pump trip. The licensee determined that Pressure Switch RR-PS-R8A or -B, which provided shutdown cooling pressure protection, had actuated, based on the lack of an alarm in the control room, component actuation consistent with pressure switch actuation, and verification of relay positions.

Maintenance technicians were dispatched to visually inspect the pressure switches and associated tubing and cabling and found no abnormalities.

The operators restarted the RHR pump and placed the reactor on shutdown cooling without further problems. The licensee is continuing troubleshooting to identify the root cause of the isolation. The licensee action to date appeared appropriate. The NRC will further evaluate the event during programmatic review of the LER.

2.2 Second Loss of Shutdown Cooling

On December 13, 1995, while CNS was in cold shutdown, the plant lost shutdown cooling for 26 minutes. The temperature increase was approximately 2°F. The plant received a full scram signal and Groups 2, 3, and 6 isolations. Group 2 was the isolation of the shutdown cooling mode of the RHR system, Group 3 was isolation of the reactor water cleanup system, and Group 6 was isolation of the secondary containment and initiation of the standby gas treatment system. The licensee reset the scram and Groups 2, 3, and 6 isolation signals and restored shutdown cooling.

The event occurred while a maintenance activity was being performed. Prior to the event, the licensee had replaced a gasket on the common reference leg of the shutdown and steam nozzle range reactor vessel level instrumentation. After this maintenance activity, the licensee noted that both instruments were reading high and determined that there was a loss of reference leg level due to the gasket replacement. The licensee directed instrumentation and controls technicians to refill that particular reference leg. However, during performance of the work, the technicians connected the water backfill to the active leg of the level instrument transmitter. This active leg was also connected to Instruments NBI-LIS-A and -B, which were not isolated. The resulting spike in these instruments caused the scram and the isolations.

The inspectors reviewed Maintenance Work Request Number 95-4427, dated December 13, 1995. The scope of this work request was to replace the flange gasket. The licensee revised this work request to add the backfilling procedure, once it was discovered that there was a loss of reference leg level. The revised work request did not contain any additional instructions under the scope of work. The inspectors reviewed Instrumentation and Control Procedure 14.4.4, "Instrument Sensing Line Backflush/Backfill," dated January 30, 1995, which resulted in the filling of both reference legs. The inspectors noted that the procedure had been reviewed and signed by control room personnel and none of the steps had been crossed out as being not applicable. The inspectors concluded that the procedure was vague in instructions. The inspectors discussed the event with the licensee personnel responsible for this activity. Originally, backfilling was to be done on Reference Leg B only. However, Step 8.1.6 of the procedure specified that both legs should be backfilled. The instrumentation and controls technicians had become confused as to the work scope and had asked their supervisor if both lines could be backfilled. The supervisor had reviewed the applicable drawings and had determined that the active leg could be backfilled without noticing that the instruments that could cause ESF signals, including a scram, were connected to the active leg.

The inspectors concluded that preplanning for this job was inadequate, and the procedure and the work request did not have sufficient detail to allow the technicians to perform their job correctly.

Immediate corrective actions included resetting the isolation signals and reviewing the expectations for proper maintenance preplanning with the involved maintenance technicians and supervisors, the control room staff, and the outage work planning organization. The failure to provide appropriate instructions for implementation of maintenance activities is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, in that the procedures provided to maintenance personnel were not appropriate to the circumstances (298/9517-02).

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

3.1.1 Control Room Shift Turnovers

The inspectors observed several crew turnovers for both morning and evening shift and found turnovers to include relevant equipment status, expected activities, plant vulnerabilities, and information regarding protected systems performance. Followup of outage work and awareness of plant vulnerabilities appeared to be strong among the control room staff.

3.1.2 Control Room Review of Outage Work

On multiple occasions inspectors observed control room staff supporting outage activities. The support provided by the control room included reviews of procedures and work orders to insure that proper equipment and clearance boundaries were specified, status of equipment was understood in the control room, and activities which affected other systems and required additional support were noted. The inspector also observed that the types and numbers of concerns raised by operations staff decreased over the duration of the outage. This appeared to be the result of better work packages provided to the control room. Based on discussions with operators and review of selected outage packages, the inspectors determined that the outage support staff and work control center had become more effective in identifying interferences and other issues requiring resolution before providing work packages to the control room. The higher level of performance by the work control center and outage planning groups was considered an improvement, since fewer challenges to the control room staff allowed better management of the reactor plant condition by the control room.

3.2 Plant Tours

During routine tours, inspectors noted that protected equipment was not compromised by work in the vicinity, that work areas were generally well-controlled, and that health physics and plant operations staff toured areas to ensure work was ongoing in a controlled manner.

3.3 Control of Refueling Operations

On November 15, 1995, the licensee commenced refueling operations. The inspector observed these operations and found them to be well controlled by licensed senior reactor operators, reactor engineers, bridge crane operators, refueling contractors and control room staff. Communications were complete and clear. Multiple verifications of required fuel positions from the spent fuel pool to the reactor vessel were communicated. Checks for control rod friction, proper fuel alignment, and bridge crane operation were performed systematically. Command and control was maintained by the senior reactor operator on the bridge crane concurrent with control room followup of procedures and move sheets for each fuel bundle. Refueling operations appeared well controlled and effectively implemented.

3.4 Torus Closeout Walkdown

On December 13, 1995, the licensee performed their final walkdown of the torus. A four-member team was formed: two people from QA, one person from Engineering, and one person from Operations. The team used Procedure 2.0.10, "Primary Containment Access Control," Revision 5.1, during their walkdown. The team found a number of different items, for example: pieces of tape and string, bolts, and tie-wraps. The items were removed from the torus.

The licensee then performed video camera recordings of the underwater areas of the most likely places objects would be dropped, underneath the entrance ladder and the area where the HPCI vacuum breakers were installed. During the recording of the underwater areas, a tie-wrap and a piece of ceramic material were found. An engineering evaluation was performed to demonstrate that the two objects would not affect the flow requirements of the ECCS by blocking the suction strainers.

The inspector performed a walkdown and identified three concerns: electrical junction boxes did not have all fasteners installed; tie-wrap conduit cable labels were not analyzed to be able to withstand high temperatures during a design basis accident; and adhesive holding plant identification labels was not analyzed to be able to withstand high temperature and moisture during a design basis accident. Engineering developed an operability assessment to disposition the three concerns. The electrical junction boxes inside the torus were associated with nonessential equipment and, therefore, sealing of these junction boxes from moisture is not required for postaccident operation. The tie-wrap conduit labels were evaluated to be able to withstand design basis accident temperature without becoming detached and contributing to ECCS suction strainer clogging. Since engineering was unable to determine the temperature limits of the adhesive, a subsequent operability assessment assumed that, if the plant identification labels fell into the water and blocked the strainers over the full surface area of the label, 1 inch by 3 inches, only a small percentage of the strainer surface area would be blocked and operability would not be affected.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 HPCI Exhaust Line Vacuum Breaker Replacement

On November 21, the inspector observed in-shop fabrication of the HPCI exhaust vacuum breaker assembly, to be installed in the torus at a later date. The inspector observed that welders followed design change instructions for proper alignment of the vacuum breakers. Welders showed excellent attention to detail in implementing drawing requirements for vacuum breaker orientation. The orientation of these vacuum breakers was important since their operation depended upon gravity assistance of swing check valves. Welders performed well controlled measurements of angle and distance from existing piping and obtained foreman guidance when required. The inspector considered this attention to detail appropriate and well-implemented.

The inspector reviewed the work instructions, design change, and weld sheets for this particular job. These documents appeared in order, although several changes had been required to proceed with work.

4.2 DG 1 Design Change Installation Problems

On October 23, 1995, inspectors identified to station management that technicians were encountering significant difficulties and ambiguities in implementing the DG 1 design change. After bringing these concerns to plant management, four additional engineering coordinators were assigned to assist with design change implementation.

Among others, the following notable problems occurred during the implementation of the modification and subsequent testing.

- On November 3, the licensee identified that fitups for DG air tubing and DG mechanical fittings for lube oil and jacket water had not been performed properly. The licensee disassembled tubing and piping to evaluate and correct poor workmanship.

- On November 10, the lube oil pump shaft was found to have broken during a test run due to incorrect fitup during installation. Vendor guidance had not been available to identify the need for careful fitup using gaskets during lube oil pump installation.

- On November 15, the diesel mechanical governor was unable to control DG speed. During the overspeed condition, the licensee identified that the overspeed setpoint was incorrectly set to 720 rpm instead of the required 656 rpm. DG mechanical governor testing resumed with continued inadequate governor performance. On November 22, the licensee was informed by Woodward Governor that the governor had a plug gauge remaining in one of the governor ports. The vendor indicated that the plug gauge's interference in the port would have caused the inadequate control of DG 1 speed as observed during testing.

- On November 20, during a full load rejection test, the diesel output breaker failed to open on loss of load and the DG attempted to pick up additional load from the bus. The licensee determined that the breaker failed to open because the test was inadequate. A controlled drawing used as a reference to write the test did not include a switch which was installed in the plant. Accordingly, the switch was incorrectly positioned during the test. The switch was for local or remote control of the breaker and had been installed several years ago.

Several additional problems were identified by QA during installation of the DG 1 design change and overhaul, which were documented on condition reports (CRs). The licensee resolved the problems within the CR process.

4.3 Licensee Evaluation of DG 1 Design Change Program Problems

The licensee stated that problems that had occurred on the diesel could be grouped into three areas. The first group consisted of conditions which changed from that expected to that found during the job, including situations such as incorrect logic wiring, inadequate test requirements, incorrect walkdown information, information specifications, and drawing deficiencies. These problems represented less than 10 percent of the problems encountered during DG 1 work. The other two areas, installation problems and constructability problems, were roughly equivalent in number of problems. Installation problems included poor craftsmanship, inadequate parts (unavailability, incompatibility, or defective parts), inaccurate as-built drawings, and additional information needed. Constructabilty problems included inadequate work instructions, inadequate acceptance testing, and the need for additional work instructions.

4.4 Programmatic Control of DG Design Change

On November 15, 1995, QA issued a CR which identified that there did not appear to be evidence that sufficient evaluation had taken place to assure that the deficiencies experienced during work on DG 1 would not occur during the modification and overhaul of DG 2. The QA basis for this description involved a chronology of over 100 individual problems with implementation of the DG 1 design change as well as the 18-month overhaul. These problems had been self-disclosing, management identified, or QA identified. Maintenance technicians had identified few DG 1 or 2 problems during overhaul implementation. NRC inspectors raised concerns regarding recovery from problems with DG 1 and implementation of lessons learned on DG 2 for both the design change and the 18-month overhaul. Subsequent discussions between the licensee and the NRC indicated that the licensee had taken several steps to provide continuity and command and control and clear expectations for coordination and implementation of the work on DG 2. Selected technicians and supervisors had been assigned. Dedicated 24-hour project management was also provided. The licensee stated these steps to resolve programmatic concerns would be taken in addition to the resolution of individual deficiencies associated with DG 1 maintenance and modification problems. The actions taken by the licensee adequately addressed the inspector's concerns.

4.5 DG 2 Injector Failures

During a 9-hour surveillance run on DG 2, two fuel lines became disengaged from the injector, spraying diesel fuel. DG 2 was immediately shut down. The licensee's investigation discovered that incorrect fuel injectors were installed on two cylinders. The incorrect fuel injectors were a new style, for which the diesel was not designed. The licensee found that the incorrect fuel injectors had been provided to the DG maintenance crews as a result of numerous improper practices in the procurement, inventory, and equipment release processes.

The first occurred when the system engineer ordered new fuel injectors for a modification that was not approved. Plant management decided not to implement the modification, which resulted in the new fuel injectors for the unapproved modification being stored in the warehouse under a new part number. The second occurred when the system engineer sent 14 old style fuel injectors back to the vendor to have them refurbished as new style fuel injectors and returned under a new part number. The vendor was unable to refurbish the fuel injectors to the new style design, so the system engineer had the fuel injectors refurbished to the old style design without changing back to the old part number. The third occurred when the system engineer modified the new part number description to fit both types of fuel injectors. As a result, when these 14 fuel injectors were returned to the licensee they were assigned the new part number. Partly because the part number and the description for that part number fit both type of fuel injectors, the receipt inspectors failed to identify the physical difference between the old and new style fuel injectors.

The last chance for the incorrect fuel injectors to be recognized before being installed on DG 2 was by the maintenance crew. The difference between the two different style injectors was not great, but a comparison of an old style injector placed next to a new style injector shows that the differences are noticeable. All of the injectors for DG 2 were replaced and, therefore, the maintenance crew had both types of injectors and did not identify that the parts were physically different.

The safety significance of this specific concern is the potential for improper fuel injector installation and ultimately fuel line leakage or the DG derating due to loss of fuel to that cylinder. The licensee stated that the remaining fuel injectors on DGs 1 and 2 were the correct injectors based on the fact that the licensee determined that only three new style injectors were received and, of these three injectors, two were installed and leaked and the third was still in the warehouse. The licensee's interim corrective action included placing all the new style injectors in the warehouse on "Administrative Hold," requiring that management sign off on all "similar fit and function" parts evaluations, and initiating a sampling plan to audit parts to verify that the parts are correct both physically and by paperwork. Based on the results of sampling plan, the licensee will determine what corrective actions will be developed.

The licensee determined in its room cause analysis that Procedure 1.1, "Equipment Spare Parts Inventory Program," lacked controls to preclude DG fuel injectors that were not of the same form and fit from being assigned the same identification code. As a result, fuel injectors that were incompatible with the existing fuel piping were installed on DG 2.

The licensee's failure to have implemented appropriate procedural controls to prevent the use of an incorrect part is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that activities affecting quality be prescribed by procedures appropriate to the circumstances (298/9517-02).

4.6 Inadequate FME Controls

On November 15, during a routine inspection tour of the drywell, the inspector identified multiple FME concerns. The drywell downcomers' foreign exclusion barriers were partially installed for some downcomers, and several wooden shims approximately 10 inches in length were found unsecured while in use to center a relief valve discharge line in the downcomer. Additionally, a drop light, a plastic boot, and miscellaneous small items were observed in another downcomer. Exclusion of foreign material from the downcomers is required to ensure foreign material is not deposited in the torus, where the vulnerability to clog emergency core cooling strainers exists. Step 8.2.3 of Procedure 0.45, "Foreign Material Exclusion Program," states that appropriate precautions shall be taken to prevent the intrusion of foreign material into systems and components. After these findings were discussed with the maintenance manager, the maintenance manager stopped work in the drywell, and management expectations were conveyed for proper FME practices. The foreign material concerns were corrected.

The failure to control foreign material in accordance with Procedure 0.45, "Foreign Material Exclusion Program," Revision 2.2, is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that procedures be properly implemented (298/9517-01).

4.7 FME Closeout Not Required for Torus Closeout

On November 30, the inspector identified that the procedure governing closeout of the torus did not include a requirement to ensure that all FME logs had been reconciled. Exclusion of foreign material from the torus is necessary to assure operability of ECCS suction strainers. The inspector identified that, although visual inspection could be performed in the torus, the visual inspection was not a complete assurance that all foreign material had been removed. Therefore, review and closure of FME logs for the torus area would be required for complete torus closure. The licensee agreed with this concern and proceeded to review logs of FME for the torus. The review identified that approximately 20 items had been removed from the torus but had not been originally logged, and approximately 30 items had been logged into the torus but had not been logged out of the torus. The licensee initiated a CR to document this problem and issued a Stop Work Order for work in the torus to assess FME controls in effect in the torus. After multiple inspections and continuing focus on FME in the torus, the licensee determined that, based on visual inspection, foreign material had been adequately removed to assure torus operability. The licensee agreed that logging of foreign material in and out of the torus had not been adequate. However, inspection and an associated engineering evaluation was considered an appropriate measure to ensure torus operability and the removal of foreign material.

Procedure 0.45, "Foreign Material Exlusion Program," Step 8.2.18, states that, before controls estaolished for an existing foreign material exclusion area can be removed, all items entered on the logs must be accounted for. Procedure 2.0.10, "Primary Containment Access Control," is the procedure utilized to formerly closeout the containment. The inspector identified that Procedure 2.0.10 was inadequate in that it did not require that Procedure 0.45 requirements be completed as a condition for containment closure. This procedural inadequacy is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires procedures affecting quality to be appropriate to the circumstances (298/9517-01).

4.8 Hose Used for Flushing Safety-Related Components Introduced Foreign Material

After maintenance of an MSIV, the licensee flushed the valve with water. After MSIV maintenance, surveillance testing and a local leak rate test were performed, which the MSIV failed. Inspection of the MSIV determined the presence of green paint chips in the valve body. The licensee removed the paint chips and later determined that the most likely source of the paint chips was a hose used to flush the valve. This hose had not been cleaned and, therefore, may have introduced the paint chips. The inspectors asked if the licensee had reviewed cases where hoses which had not been cleared of foreign material were used to provide flushing water or air to plant components. The licensee responded that this was the only incident where a system was filled without using equipment installed in the plant. The maintenance supervisor stated this was an isolated case, that maintenance usually uses installed plant equipment, and that hoses are generally used only for draining systems. During CR resolution, the licensee will evaluate whether there is a need to develop a program that would control the use of hoses in accordance with the CR which documented the paint chip problem. Procedure 0.45, Step 8.2.15, states that all tools and parts entering a foreign material exclusion area shall be in good repair and visually clean of debris, shipping plugs, and preservatives. The failure to preclude introduction of foreign material into the valve is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, which requires that procedures appropriate to the circumstances be implemented (298/9517-01).

4.9 FME Program Implementation Problems With Respect to Licensee Evaluation of ECCS Suction Strainer Clogging

The inspectors noted that the licensee's response to NRC Bulletin 95-02 indicated that the licensee could assure operability of the suction strainer in large part due to the effectiveness of their FME controls. Based on the problems associated with FME observed by the inspectors during this outage, the licensee was questioned as to the adequacy of suction strainer clogging prevention if FME program compliance was a primary element. The inspector also identified that analysis of suction strainer clogging for individual FME concerns had not been evaluated for the cumulative effects of all potential strainer clogging concerns. The licensee responded that, before torus closeout, underwater camera inspections had been performed for higher FME risk areas of the torus, that circulation of torus water had been performed, and then there was an immediate inspection of the RHR suction strainers, which indicated no clogging. Additionally, the licensee stated that a CR had been written to address the programmatic aspects of the multiple individual loss of FME control which had occurred, and an initiative to revise and integrate the FME program in a more effective manner would be made. This effort was expected to be performed between the end of this outage and the beginning of the next refueling outage.

The inspectors questioned the licensee as to whether an interim program would be made available in the event of a forced shutdown. The licensee stated that the same controls would be in place as required by their current FME procedure if a forced shutdown took place before April 1996. The licensee's new FME requirements were given an internal due date for completion by the end of March 1996. This addressed the inspector's concerns.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 MSIV Instrument Air Accumulator Check Valve Surveillance

The inspectors reviewed Surveillance Procedure 6.2.2.2.6, "ADS Accumulator Test," Revision 14. The inspectors noted that the acceptance criteria for both the inboard and outboard MSIV accumulator pressure was 85 pounds. The inspectors noted that under accident conditions pressure in the drywell may be higher than pressure outside the drywell. In this case, the motive force for the MSIV accumulator, which is designed to maintain the MSIV in a closed position for 1 hour after loss of instrument air, may be opposed by pressures as high as maximum drywell pressures expected during a design basis accident. The licensee provided calculations which established a basis for the MSIV accumulator pressure. These calculations noted that, for the inboard MSIVs, both the springs and the accumulators are necessary to shut and maintain the valve shut for 1 hour, while either the spring or the accumulator are sufficient for the outboard valves. The inspector verified that this information was reflected in the Final Safety Analysis Report. This concern appeared to have been properly addressed. No further issues were identified.

5.2 Hydrostatic Pressure Test

On December 19, 1995, the inspector reviewed Special Procedure 95-128, "ASME Class 1 Hydrostatic Pressure Test," Revision 0. The inspector found the operator performing the procedure to be knowledgeable on how to control the reactor vessel pressure and temperature limits. During the discussion with the inspector, the operator stated that, to preclude challenging a safety relief valve, Main Steam Drain Isolation Valve MS-MOV-M079 was to be opened to mitigate a pressure spike and protect the safety relief valves from being challenged, which corresponded with the procedure.

The inspector noted that the maximum test pressure limit was 1128 psig and asked what assurance existed that the valve would be able to open under expected differential pressure in the event of a pressure spike. Engineering determined that the valve was designed to open and close under a maximum differential pressure of 1146 psid. Since the hydrostatic test involved an almost solid reactor coolant system, a sudden pressure spike could quickly surpass 1146 psid and challenge a relief valve before the operator could take actions to mitigate the pressure spike. An on-the-spot change was made to the procedure to have the operators secure the control rod drive pumps, which provide the reactor coolant system pressure, instead of using Valve MS-MOV-MO79 to mitigate a pressure spike.

When initially questioned by the inspector, the operator not only knew to use the valve but also to secure the control rod drive pumps if pressure continued to increase. The inspectors concluded that this was an example of an inadequate engineering review in that engineering designated a component to perform a desired function without understanding that the component's design rating could be exceeded under the circumstances in which it was called on to perform its function. The licensee agreed that the valve rating had not been properly evaluated for its expected function in the test.

5.3 DG 1 Sequential Load Test

The licensee performed a sequential loading test on DG 1 in accordance with Surveillance Procedure 6.1DG.302, "Undervoltage Logic Functional, Load Shedding, and Sequential Loading Test," dated December 12, 1995. DG 1 had been running for approximately 1 hour before it tripped. Initially, the licensee believed that DG 1 had tripped on high jacket water temperature, but further investigation revealed that DG 1 had tripped on high connecting rod bearing temperature. The bearing temperature sensors had tripped DG 1 on left cylinder connecting rod Bearings 3, 4, and 6. The licensee inspected the bearings and determined no damage had been done. However, the licensee found that on one of the bearings a part of a bearing trip bar lever had broken off and was suspected to be in the sump. The licensee stated that the piece would be retrieved. In addition, the licensee was investigating why they had not received a high lube oil temperature alarm prior to the high bearing temperature.

Prior to performing the test, the licensee had extensively revised the test procedure due to a recent modification. After the diesel trip, the licensee determined that there was an error in the procedure which caused the solenoid valve of the 6-inch service water supply valve, SW AOV-2797AAV, to be energized, which closed the valve. The normal position of the valve during routine operation when the diesel is not running is energized closed. The valve would fail open when deenergized. During the test, the licensee had installed a jumper across Relay 4MX4 for the logic system functional test. Step 8.2.76 of the procedure called for pressing the emergency-to-normal reset button, which restored the system to a manual control mode. The licensee determined that the jumper across Relay 4MX4 should have been removed prior to this step to avoid energizing and closing the service water valve. The procedure had the removal of this jumper in Step 8.2.208. The licensee stated that when they had reached Step 8.2.104.6 the diesel alarm had come in.

The engineering evaluation concluded that DG 1 had not been adversely affected by the high temperature, since the temperature had not risen significantly. The vendor concurred with this assessment. The inspectors concluded that an inadequate procedure had been the cause of the diesel trip and that inadequate reviews of the surveillance procedure failed to identify the vulnerability associated with the DG 1 cooling water jumper. The failure to provide a procedure appropriate to the circumstances of DG testing is considered a violation of 10 CFR Part 50, Appendix B, Criterion V (298/9517-02).

6 ONSITE ENGINEERING (37551)

6.1 Identification of Loss of Configuration Control by Valve Vendor

On November 9, 1995, the licensee identified that several components and piece parts of valves supplied and documented by a vendor (Anchor Darling) were inconsistent with licensee design drawings and as-built configurations. These drawings also provided the basis for the limiting component analysis associated with the licensee's NRC Generic Letter 89-10 valve program.

The licensee identified the following types of vulnerabilities associated with the loss of configuration control. Material types and characteristics for commercial grade materials were assumed, rather than verified, for valve components such as actuator mounting and adapter plates, actuator mounting cap screws, actuator plate-to-yoke cap screws, and, in one case, a stem nut. Limiting component analysis assumed incorrect fastener dimensions based on incorrect drawings. The root causes for these incorrect drawings and parts appeared to stem from one or more of the following: incorrect assumptions made by vendor engineers, licensee failure to update the vendor concerning modifications, incorrect vendor calculations, lack of clear ownership of valve configuration, or vendor calculations were not properly reviewed and/or verified.

The licensee responded by performing as-built walkdowns of valve components and fasteners. The licensee also sent a QA auditor and a valve engineer to the Anchor Darling plant to perform an inspection of the design control. The licensee conducted several conference calls with NRC Region IV and headquarters staff to discuss these findings.

The licensee has conducted a 100 percent walkdown of Generic Letter 89-10 valves and has identified other inconsistencies in parts supplied by Anchor Darling. These inconsistencies appeared to have been caused by unverified and incorrect changes in Anchor Darling configuration records which were made after original construction valves were sent by Anchor Darling to Cooper Nuclear Station.

The licensee is continuing operability evaluation and part validation for several affected valves. To date, the limiting components analysis as well as other analysis required to evaluate these discrepancies have not identified an operability concern. The licensee stated that operability concerns were possible, although not likely, since most of the inconsistencies appeared to be close to the original requirements, i.e., a 1-inch diameter fastener on the drawing versus a 7/8-inch diameter fastener installed on the valve. Since limiting component analysis as well as code-required analysis requires that 0.6 of yield strength not be exceeded, it is unlikely that yield will be exceeded if most inconsistencies are close to the original requirements.

During this evaluation and investigation, licensee QA provided a leadership role in aggressively pursuing and identifying concerns as well as bounding the issue despite the heavy outage work load. Licensee engineering provided technical expertise. Licensee QA involvement appeared to be probing and aggressive. Past operability of valves affected by the configuration control problems is an unresolved item (298/9517-03).

6.2 Spent Fuel Storage Rack Reactivity Control

During review of spent fuel pool configuration, the inspector reviewed fuel storage rack configuration. Visual observations indicated that the fuel pool had excellent clarity and well-controlled fuel cell inventory. However, additional equipment and tools were suspended from fuel pool railings by over 40 ropes and cords. The licensee stated that, after the refueling outage ended, an inventory of these tools would be taken and several of these suspended tools would be moved to permanent locations or removed.

The inspector questioned the validation of the boron reactivity control provided between rows of fuel, since no difference in fuel separation between rows versus columns of fuel was evident. The licensee provided drawings and validation records showing that the boron absorber agent had been personally observed and validated during assembly to be in the proper positions and welded under engineer observations in accordance with a design change validation procedure. The assembly drawings indicated only a slight difference in spacing between rows and columns of fuel plates, which was consistent with the as-observed boron absorber space between columns of fuel. The inspector reviewed these records as well as later validation of neutron source check of the neutron absorption properties of the spacers. The neutron absorber appeared to function as expected in each of the rack walls in which it was installed. No further NRC concerns were identified.

6.3 Evaluation of REC Piping Insulation With Respect to the Potential to Clog Torus Suction Strainers

The licensee removed an outer jacket of tape from REC piping in the drywell. This tape was removed due to the licensee identified potential concern with ECCS suction strainer clogging being potentially caused by the adhesive and the tape not being qualified for a LOCA environment. The inspector noted that, beneath the tape, the REC piping was wrapped with insulation to prevent condensation. This insulation was exposed to the drywell environment upon removal of the tape. Upon review of the evaluation of the susceptibility of this insulation to clog ECCS suction strainers, the inspector found that the licensee's evaluation stated that the insulation was expected to stay installed on the REC piping and, in the unlikely event it is dislodged under LOCA conditions, must travel a tortuous path to the downcomer before it would reach the torus and potentially become clogged on the suction strainer. Therefore, suction strainer clogging would be unlikely. The NRC inspector identified that the licensee had not evaluated the insulation's structural characteristics under the conditions of heat and humidity expected during LOCA conditions. A QA inspector also identified that the path from the REC piping to the downcomer was direct rather that tortuous. The licensee agreed that these issues had not been properly addressed.

In discussion with the manufacturer of the insulation, the licensee found that, under elevated temperatures and pressures expected in the drywell under LOCA conditions, the insulation would be expected to become friable and, if dislodged from the piping, would maintain its buoyancy a an expanded foam. Therefore, suction strainer clogging would be highly unlikely. The licensee raised this issue in the boiling water reactors owner's group working group for resolution of suction strainer clogging issues as a potential generic issue. The initial evaluation was incomplete, however, the licensee's response to the inspector's findings appeared prompt and appropriate. The conclusion of the safety performance remained the same, therefore, no further NRC action is required.

7 PLANT SUPPORT ACTIVIT' (71750)

Inadequate Shipping of Radioactive Materials

On December 18, 1995, the licensee identified that a shipment received by the licensee did not comply with shipping regulations in that radiation measurements at the surface of the container were as high as 2.5 mr/hr, which exceeded the requirements of less than 0.5 mr/hr. The licensee informed the shipper and the NRC. NRC Region IV informed Region II, who had cognizance of the shipper's license requirements, and will take appropriate actions. The identification of package radiation levels higher than maximum limits was a strength.

8 FOLLOWUP - ENGINEERING (92903)

(Open) Unresolved Item 298/9514-01: Incorrect Installation of Steam Tunnel Blowout Panel

During routine inspection of accident mitigation equipment, the inspector identified that the main steam tunnel blowout panel did not appear to be constructed in a fashion consistent with design calculations. A coating had been placed on the secondary containment side of the panel which appeared substantial. In addition, other concerns described later in this section indicated that design control of this panel had not been maintained.

On November 9, 1995, the licensee declared the main steam tunnel blowout panel inoperable due to a coating of fiber glass over the panel which would have strengthened it and prevented it from operating at 0.52 psig as required.

Because original construction drawings could not be obtained for the panel, the original design calculation had not been verified, and because the basis for the acceptance criteria of 0.52 psi could not be located, the licensee determined that reconstruction of the design basis for the panel was necessary to evaluate panel operability.

The licensee identified that the blowout panel on the wall between the main steam tunnel and the turbine building should operate in order to relieve pressure as well as the door leading from secondary containment into the steam tunnel. The inspector noted that the door did not have specification requirements to fail at a particular pressure, as expected for devices used to relieve pressure.

On November 21, the licensee issued a 10 CFR 50.72 report identifying to the NRC that the steam tunnel blowout panel was outside its design basis. The licensee had declared it inoperable for purposes of pressurized reactor coolant system operation. However, the panel was declared operable for purposes of secondary containment operability during refueling and shutdown conditions. The panel has now been modified to ensure it will relieve steam line break pressure at less than 0.52 psid. Further licensee evaluation of past operability is continuing.

9 IN-OFFICE REVIEW OF LERs (90712)

The inspectors performed a review of the following LERs associated with operating events. Based on the information provided in the report, review of associated documents, and interviews with cognizant licensee personnel, the inspectors concluded that the licensee had met the reporting requirements, addressed root causes, and taken appropriate corrective actions. The following LERs are closed:

- 298/93-027, Revision 0: Secondary Containment Operability Concerns During the Past Operating Cycle
- 298/94-005, Revision 0: Inoperable Appendix A Fire Barrier Penetration Seal Resulting From Inadequate Initial Installation
- 298/94-006, Revision 1: Inoperable Control Room Emergency Filter System
- 298/94-008, Revision 0: Inoperable Appendix A Fire Barrier Penetration Seal Resulting in Inadequate Initial Installation
- 298/94-010, Revision 1: Closure of Shutdown Cooling Isolation Valves Due to Leakage Through the Minimum Flow Valve

- 298/94-016, Revision 0: Inadequate Isolation of Diesel Generator Control Circuits
- 298/94-016, Revision 1: Inadequate Isolation of Diesel Generator Control Circuits
- 298/94-027, Revision 0: Installation of Unqualified Relay in Potential Harsh Environment
- 298/94-027, Revision 1: Installation of Unqualified Relay in Potential Harsh Environment
- 298/94-030, Revision 0: Inspection of Fire Barrier Requirement by Unqualified Inspector Requirement
- 298/94-031, Revision 0: Calibration Frequency Error for Temperature Switches
- 298/95-007, Revision 0: Iodine Channel of Control Room Air Sampling Monitor Found Out of Calibration Tolerance
- 298/95-007, Revision 1: Iodine Channel of Control Room Air Sampling Monitor Found Out of Calibration Tolerance
- 298/95-009, Revision 0: Fire Suppression Water System Did Not Meet Minimum Requirements for Operability
- 298/95-015, Revision 0: Transfer of Bus F to the Emergency Transformer Due to a Maintenance Activity
- 298/95-016, Revision 0: Control Room Emergency Filter System Inoperable For 9 Minutes During Refueling Operations Due to Personnel Error

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. Bremer, Acting Operations Manager
J. Dillich, Maintenance Manager
C. Gaines, Event Analysis Manager
J. Gausman, Plant Engineering Manager
R. Godley, Licensing Manager
P. Graham, Senior Engineering Manager
J. Hale, Radiological Protection Manager
J. Herron, Plant Manager
R. Jones, Senior Manager Safety Assessment

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

2 EXIT MEETING

An exit meeting was conducted on December 18, 1995. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee did not express a position on the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

On January 18, 1996, the enforcement actions taken as a result of this inspection were discussed with the Manager, Nuclear Licensing.