APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/94-28

License: DPR-46

Licensee: Nebraska Public Power District
P.O. Box 499
Cclumbus, Nebraska

Facility Name: Cooper Nuclear Station (CNS)

Inspection At: Cooper Nuclear Station, Brownville, Nebraska

Inspection Conducted: September 11 through October 22, 1994

Inspectors: R. Kopriva, Senior Resident Inspector, CNS
W. Walker, Resident Inspector, CNS
R. Mullikin, Senior Resident Inspector, Fort Calhoun Station
H. Freeman, Resident Inspector, Palo Verde
I. Barnes, Technical Assistant, Division of Reactor Safety

Approved: P. H. Harrell, Chief, Reactor Projects Branch C — Date 12/7/94

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite response to events, operational safety verification, plant support activities, maintenance activities, review of Temporary Instruction 2515/125, engineering followup, followup on corrective actions for violations, onsite review of licensee event reports.

Results:

Plant Operations

- Operations personnel were identifying concerns and deficient conditions during routine tours of the facility, which was a noted improvement over the performance level of this group in the past (Section 3.1).

- The Operations department actively participated in the plant daily status and planning meetings. In previous meetings, the Operations department was hesitant to contribute to these meetings. This is an indication that management has instituted a policy that is focused on safe operation of the facility (Section 3.1).

Maintenance

- Inadequate consideration was given to properly covering the pump shaft casing during performance of preventive maintenance on Service Water Pump (SWP) B, which could have allowed the introduction of foreign material into the pump (Section 5).

Engineering

- As a result of the review of the reactor core isolation cooling (RCIC) system, it was noted that the system engineer was not aggressive in resolving system issues and the engineer was not familiar with the system to which he was assigned (Section 8.2).

- Engineering personnel developed operability determinations to address licensee-identified hardware deficiencies, and the determinations addressed the appropriate factors to resolve the operability status of the affected equipment (Section 8).

Plant Support

- Based on the various observations made by the inspectors, it was apparent that the licensee was instituting an effective radiological protection program (Section 4.1).

- The security program was implemented in a satisfactory manner (Section 4.3).

Management Overview

- Based on the reviews performed by the inspectors of the licensee-identified deficiencies with Fire Hazards Analysis, it was noted that the licensee was proactive in identifying and addressing these long-standing deficiencies. The actions taken by the licensee were an indication of a newly initiated approach to actively identify and resolve plant issues, which is a positive reflection of the effectiveness of the new plant management staff (Section 2.1).

- Licensee management was effective in performing the appropriate inspections after a leak was identified in the reactor equipment cooling (REC) system. The actions taken to address the generic aspects of this issue were considered to be good (Section 2.2).

Summary of Inspection Findings:

- A noncited violation was identified (Section 2.1.2).

- A noncited violation was identified (Section 2.1.4).

- Violation 298/9414-02 was closed (Section 9).
- Licensee Event Reports 298/93-06, 298/93-36, and 298/94-08 were closed (Section 10).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

The plant remained in an unplanned shutdown throughout this inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Review of Licensee-Identified Fire Hazards Analysis Deficiencies

2.1.1 Deviations From Appendix R Combustible Loading in Fire Areas

The licensee discovered, during review of the Fire Hazards Analysis, that the basis for certain NRC-approved exemptions from 10 CFR Part 50, Appendix R, were incorrect. Specifically, it was determined that the combustible loading in certain areas was greater than described by the exemption requests that had been submitted to the NRC. The following discrepancies were discovered by the licensee:

- Auxiliary Relay Room - Combustible loading was originally described as approximately 15,000 Btu/ft^3. The recalculated loading was determined to be approximately 57,000 Btu/ft^3.

- Reactor Building (903-foot elevation) - Combustible loading was originally determined to be approximately 20,000 Btu/ft^3, but was subsequently recalculated to be 36,000 to 67,000 Btu/ft^3.

The licensee submitted exemptions from the criteria of Appendix R for these areas of the plant, with the requests describing the combustible loading in these areas. The exemptions granted by the NRC's Office of Nuclear Reactor Regulation (NRR) were based, in part, on the licensee's statement of combustible loading levels in the areas. The recently identified increase in combustible loading was mainly due, according to the licensee, to a more conservative methodology used for calculating the combustible loading for installed electrical cables.

The licensee contacted NRR about the change in combustible loading and NRR will be reviewing the combustible loading deviation to determine if the previous exemption requests will have to be resubmitted. Although the combustible loads in these fire areas differ from the approved exemption, the inspector concluded that the errors were not due to any mistake by the licensee at the time the exemption requests were submitted. In addition, the inspector also noted that the increase in combustible loading did not significantly affect safe operation of the facility.

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2.1.2 Critical Switchgear Rooms Fire Seal

The licensee also discovered, during review of the Fire Hazards Analysis, that the bus duct seal between the two critical (i.e., safety-related) switchgear rooms was never installed. Condition Report 94-0552 was issued by the licensee to describe this discovery.

The wall between the two critical switchgear rooms is a 3-hour rated fire barrier. Since the bus duct that passes through the wall was not internally sealed, the licensee committed, in a 1983 exemption request, to seal the duct in order to make the duct a 3-hour rated fire barrier. The exemption was granted based upon this commitment; however, for reasons that could not be determined, the licensee never installed the seal in the bus duct. Section III.G.2 of Appendix R requires that redundant trains of equipment, required for safe shutdown of the plant, be separated by a 3-hour rated fire barrier.

In 1986, the licensee discovered that the duct was not internally sealed and completed Engineering Evaluation 86-03 to justify the presence of an unsealed bus duct penetration in the barrier separating the two critical switchgear rooms. The licensee concluded that the ability to safely shut down the plant was not affected by the unsealed duct. The licensee completed another evaluation (Engineering Evaluation 89-02) in 1989 to again justify the lack of a bus duct seal. The licensee again concluded that the installed configuration was adequate.

NRC Generic Letter 86-10, "Implementation of Fire Protection Requirements," requires that an evaluation be performed by a fire protection engineer and retained for future NRC audit when the licensee chooses not to seek prior NRC review and approval of changes to the Fire Hazards Analysis. Generic Letter 86-10 is not applicable in this case since the licensee did seek prior review by NRR of a change to the fire protection program as evident by the exemption request. This position was conveyed by NRR in a telephone conference with the licensee on August 15, 1994. During the telephone conference, NRR further indicated the need for the licensee to implement appropriate compensatory measures in the form of continuous fire watches in the affected areas, which the licensee agreed to and did initiate.

The failure to install and maintain a fire barrier in conformance with Appendix R, Section III.G.2, without an approved exemption, is a violation of NRC requirements. However, this violation of the fire protection program was identified by the licensee during a self-initiated update of the Fire Hazards Analysis. In addition, the licensee took appropriate compensatory and corrective action measures when these deviations were identified and the problems were determined to be of minor safety significance; therefore, this violation will not be cited, as the criteria of 10 CFR Part 2, Appendix C, Section VII.B.2, were satisfied.

The inspector discussed the deviations with NRR regarding the actions that needed to be performed by the licensee. NRR stated that the licensee would

have to initiate the exemption evaluation process to resolve the identified deviations. The licensee agreed to submit the necessary documentation to NRR to reconcile the identified discrepancies, with the understanding that the compensatory actions would remain in effect until the NRC formally approves the revised bases for the exemptions.

2.1.3 Emergency Lighting Walkdown

The inspectors performed a walkdown of the adequacy of the emergency lighting units, which are required in order that an operator can complete the actions specified in Emergency Procedure 5.4.3.2, "Postfire Shut Down to Cold Shutdown Outside Control Room." The inspectors assessed the emergency lighting system to verify that an operator could traverse to the required areas and could locate and operate a piece of equipment required for a safe shutdown of the facility.

The inspectors assessed the emergency lighting in the control and reactor buildings and noted that the quantity of emergency lighting units were sufficient. The inspectors also noted that the lamps on the emergency lighting units were sealed in place and the performance of a routine surveillance test ensured that the lamps were maintained in the proper alignment.

The inspector requested the results of any emergency lighting test or inspection that assessed illumination with normal lighting turned off. The licensee provided the results of Special Test 87-01, "Eight Hour Emergency Lighting Inspection." This 1987 test was performed by operations personnel and provided instructions to align the lamps to optimize illumination of safe shutdown routes and equipment. The test results indicated a detailed walkdown with several discrepancies noted, which were subsequently corrected. The lamps were sealed in place after proper alignment was made. The inspectors concluded, based upon the walkdown and results of Special Test 87-01, that the installed emergency lighting was sufficient to satisfy the requirements Appendix R, Section III.J.

However, during the walkdown, the inspectors observed that small labels, which were installed to indicate that a component was required for alternate shutdown, were installed on a few motor control center breakers. The inspectors discussed this labeling discrepancy with the labeling coordinator to determine whether this was the beginning of a widespread labeling program. Labels are sometimes used to help an operator easily locate a piece of equipment during times when the only source of light is the emergency lighting units. The licensee informed the inspectors that there were some labels used in the past and all but a few were removed. The licensee stated that the labels that were left were not easy to remove or might cause an inadvertent actuation of a relay in the cabinet. The inspectors informed the licensee that, whether labels are installed or not, there should be consistency. The licensee stated that the inconsistency would be resolved in the near future.

2.1.4 Diesel Generator Alternate Shutdown Capability

This item, discovered by the licensee during a self-assessment, involved a problem where a fire in certain areas of the plant could prevent Emergency Diesel Generator (EDG) 2 from starting. EDG 2 is the diesel that the licensee has dedicated for safe shutdown purposes.

Since the EDG control circuit was not double fused, the licensee maintained compliance with Appendix R, Section III.L, by specifying, in the safe shutdown procedure, that a manual breaker located inside the EDG 2 control panel be closed. However, there was not sufficient emergency lighting in the area of the EDG 2 control panel for the operators to perform this function.

The inspector reviewed the licensee's actions with regard to this finding. The licensee initially planned to install emergency lighting and revise safe shutdown procedures to instruct operators to open the control panel and shut the breaker. However, the licensee determined that a plant modification, which would remove the breaker and add separate fusing to the control room alarm circuitry and isolate a fault in the circuit, was more appropriate. This modification was planned to be installed prior to plant restart in accordance with the instructions provided in Design Change 94-263, "Fuse Modification for DG Engine Control Panels."

The inspector reviewed the design package and concluded that the planned modification would bring this circuit into compliance with the requirements of Appendix R. Although this item had the potential for disabling EDG 2 during certain fire scenarios, this item was considered to be of low safety significance since the probability of a fire occurring in the specific location required to disable the EDG had a very small probability. Thus, this will not be cited because the criteria specified in Section VII.B.2 of Appendix C to 10 CFR Part 2 were satisfied. Specifically, this item was identified by the licensee, it is of low safety significance, appropriate corrective actions were implemented, and the condition was reported.

2.1.5 Declaration of a Notice of Unusual Event Due to EDG Inoperability

On October 6, 1994, the licensee discovered, while performing a design bases document review, that the carbon dioxide (CO_2) pressure switches for both EDG rooms were in the same fire area. The pressure switches were designed to sense when the CO_2 system actuates and then stop the ventilation system in the affected EDG room to prevent unwanted removal of the CO_2. The failure to secure the ventilation system could prevent the extinguishing of a fire in an EDG room. A fire outside of the rooms could affect the cabling to these pressure switches and could prevent the EDG room ventilation system from performing its intended function (i.e., providing cooling to the EDGs when they are operating). Operation of the EDGs without the ventilation system could potentially render the EDGs inoperable due to overheating.

The licensee's immediate corrective action was to establish a continuous fire watch, which was located between the two EDG rooms. The inspectors

interviewed several of the fire watches in the EDG rooms to assess their knowledge of their duties. The fire watches were aware of their duties, as specified in Administrative Procedure 0.39, "Fire Watches." In addition to the requirements of Procedure 0.39, the fire watches were given written instructions by the fire protection engineer to close the door, if a fire was to start, before exiting the area. The inspectors observed that the fire watches were properly performing their duties, with one exception. While a 4-hour run of EDG 1 was occurring, the fire watch was posted inside the door of the EDG 2 room to minimize noise impact on the individual. The inspectors noted that the fire watch was positioned in a chair next to a large electrical panel, which obscured the view of the EDG 1 room. The inspectors notified the fire protection engineer and he promptly had the fire watch moved for a better view of the EDG 1 room and still minimized the noise level.

On October 7, the licensee, after further evaluation, declared a Notification of Unusual Event due to the CO_2 pressure switches being in a nonseimic structure. The basis for the declaration of the declaration was that a seismic event had the potential to also disable the EDG room ventilation.

The licensee's immediate corrective action was to install a temporary modification, which defeated the shutoff of the ventilation system upon a CO_2 system actuation. The fire watch duties were to notify the control room when the CO_2 system actuated so the fire brigade could be dispatched if a fire were to occur. The licensee exited the Notice of Unusual Event when these actions were completed.

The licensee's actions were considered appropriate by the inspectors as the licensee addressed all the safety aspects of this issue.

2.2 Followup on REC System Leakage

On turnover from construction in January 1973, the REC system was filled with demineralized water containing a 500 ppm concentration of the corrosion inhibitor Dearborn 524 (i.e., 55 percent sodium nitrite, 40 percent sodium tetraborate pentahydrate, 3 percent sodium hydroxide, and 2 percent mercaptobenzothiozole). As a result of General Electric concerns with respect to the use of this corrosion inhibitor in the REC system [i.e., the inability to remove the organic compound (mercaptobenzothiozole) in a filter/demineralizer system with the resulting potential for entry into the primary systems and the presence of a boron compound with the potential for creating a reactivity problem]. the licensee drained the system in April 1973 and refilled it using demineralized water containing a 200-1000 ppm concentration of sodium nitrite as a corrosion inhibitor. Soda ash was also added to adjust the system pH to a range of 8-10. The inspectors determined, from discussions with licensee chemistry staff and review of chemistry records, that only small additions of soda ash were required to be made, and for only a limited time following system fill, to obtain and maintain the desired pH range. The inspectors also noted, from review of early procurement records, that the sodium nitrite purchased by the licensee was specified to be

furnished as "technical grade." No documentation was available that defined what compositional limits were ensured by this procurement requirement.

Initial throughwall leakage in the REC system occurred in August 1977. An additional eight occurrences were documented in 1979, with a further two instances recorded in January 1980. A 6-inch diameter, pipe-to-elbow sample containing a throughwall defect was removed in 1979 and sent to General Electric for metallurgical examination. The preliminary report of the laboratory examinations, transmitted by a General Electric letter dated January 22, 1980, concluded that crack initiation consistently occurred in the crevice formed by the weld backing ring on the inside of the pipe. The failure mode was determined to be nitrate-induced, intergranular stress corrosion cracking, with the backing ring crevice considered to be a major contributor to the failure. Intergranular attack was also found in the backing ring, pipe material, and elbow material, which indicated that the corrosion environment was sufficient to produce degradation, even if stress was not present. The inspectors also noted that the preliminary report stated that activities were continuing to more precisely define the role of water chemistry additions of the cracking in creviced regions. The preliminary report also stated that a final report would be issued; however, the inspectors determined that a final report was never issued by General Electric. In addition, the licensee could not provide any documentation or explanation as to why a final report was not issued or information to indicate that the licensee had performed a followup to obtain a final report.

During review of historical chemistry data, the inspectors noted that samples of REC water were forwarded to an outside laboratory in February 1980 for analysis. The results obtained by the laboratory indicated that the nitrite levels were consistent with a specified 200-1000 ppm sodium nitrite concentration as the level in the REC system was 861 ppm. The inspectors noted, however, that the reported nitrate value was 3065 ppm for the REC water sample. These values confirmed that nitrate-induced, stress corrosion cracking was the failure mechanism. The inspectors were informed by the Materials and Chemical Engineering Branch staff of NRR that a strong oxidant would be needed to convert sodium nitrite to sodium nitrate. Thus, the inspectors concluded that it was unlikely that the nitrates were formed during operational service by the interaction of sodium nitrite with dissolved oxygen present in the water. The most probable explanation for the presence of nitrate anions was that nitrates had been inadvertently added to the REC system.

Review of historical chemistry data for the REC system by licensee staff, for the 1973-1980 period when sodium nitrite was used, also indicated that the conductivity measurements were higher than what would be expected from the sodium nitrite concentrations present. Thus, it appeared that other anions were present in the REC water. The absence of nitrate data for most of this period precluded specific verification that nitrates were responsible for the increased conductivity values.

The inspectors noted that a General Electric letter, dated June 17, 1980, addressed the degradation mechanism and recommended that demineralized water without chemical additives be used in the REC system. General Electric suggested that the conductivity of the water in these systems be maintained at 1 micromho/cm, with corrective action taken if the conductivity exceeded 3 micromhos/cm. An additional recommendation was made to hydrotest the systems to ensure that there was negligible leakage. The inspectors noted, from review of chemistry records, that the licensee implemented the use of demineralized water in the REC system and adopted the conductivity criteria suggested by General Electric in 1980. However, no documentation was found by the licensee that indicated that the recommended hydrostatic test of the REC system was ever performed. The inspectors were informed that no further leaks had been identified in the REC system, after filling the system with demineralized water in 1980, until a leak was discovered on July 28, 1994. The inspectors confirmed this information by reviewing a sample of work requests for the REC system, covering the 1980-1994 period, and not identifying any evidence of the documentation of leaks in REC system.

On July 28, 1994, a pinhole leak was discovered in a 12-inch diameter pipe weld in the nonessential (i.e., nonsafety-related) portion of the REC system. The leaking weld was located at a tee where the return from the nonregenerative heat exchanger combines with the return line from the drywell. The licensee recorded discovery of the leak in Condition Report 94-0485.

A section containing the leaking weld was sent to General Electric for metallurgical examination. The preliminary results of that examination indicated that the leakage resulted from the propagation of nitrate-induced, intergranular stress corrosion cracks from a crevice created by a weld backing ring on the inside surface of the pipe. General Electric also concluded that the cracking was similar to that observed in 1979 and 1980 in the REC system.

The inspectors noted that the initial response by the licensee was the ultrasonic examination of 30 REC system weld joints. The criteria used for selection of this sample included all welds repaired in 1979 and welds adjacent to the recently discovered cracked weld. A second pinhole leak was discovered on July 29, 1994, during preparation of a 6-inch diameter pipe weld (in the nonessential portion of the REC system) for ultrasonic examination. This weld was also located in the REC return line from the nonregenerative heat exchanger, at a location closer to the heat exchanger. Ultrasonic examination of the sample welds resulted in the detection of cracking in four 6-inch diameter pipe welds in the nonessential portion of the REC system. After sizing by ultrasonic examination, the cracks were evaluated by linear elastic fracture mechanics analysis, using ASME Code Section XI, Class 1, acceptance criteria. All four welds were found to meet this acceptance criteria. The identified degradation was considered by the licensee to also be potentially present in the essential REC system piping and, as a result, a plan was developed and implemented by the licensee.

The licensee's inspection plan for inspection of the essential REC piping utilized the methodology contained in EPRI NP-5380, "Visual Weld Acceptance

Criteria, Volume 2: Sampling Plan for Visual Reinspection of Welds (NCIG-02, Revision 2)." The sampling approach was structured to provide 95 percent confidence that 95 percent of the items in the population met the ASME Section XI Code, Class 1, linear elastic fracture mechanics analysis acceptance criteria contained in Subsections IWB-3500 and -3600. A sample of 67 essential welds, which exceeded 10 percent of the essential welds with backing rings, was randomly selected for ultrasonic examination. Radiographic examinations were first performed on small-bore piping welds (i.e., up to 2 1/2-inches in diameter) in the sample because of initial questions regarding the capability of the ultrasonic examination technique to identify and size defect indications. Ultrasonic examinations of the sample welds detected one flaw indication (1.5 inches long with a maximum depth of 0.190 inches) in a 12-inch diameter, essential REC pipe weld that required fracture mechanics analysis. The pipe wall thickness at this location was 0.42 inches. This indication was determined to meet the Subsection IWB-3600 acceptance criteria. Radiographic examination also identified a defect indication in a 2 1/2-inch diameter, small-bore weld. During conditioning of the crown of this weld, to permit sizing by ultrasonic examination, the weld leaked, which indicated the defect was throughwall. This defect represented a failure to meet the inspection plan acceptance criteria and required the examination of an additional 50 welds.

Defect indications were found in three of the additional 50 welds. The pipe diameters containing the defects were 2 1/2, 3, and 8 inches. The respective sizes of the defect indications, by increasing pipe size, were 2 inches long with a maximum depth of 0.150 inches, 1/2 inch long with a maximum depth of 0.030 inches, and 3 inches long with a maximum depth of 0.210 inches. Each defect indication was determined to meet the acceptance criteria of Subsection IWB-3600. This status (a total of one failure to meet inspection plan acceptance criteria) satisfied the inspection plan sampling requirements, thus completing required ultrasonic examinations.

The inspectors concluded that the approach used by the licensee provided reasonable assurance that the structural integrity of the REC system was adequate until the next refueling outage. Licensee personnel indicated that the flaw indications that had been detected would be repaired by welding prior to plant startup. The inspectors reviewed Maintenance Work Request (MWR) 94-4300, which pertained to the repair and pneumatic test of the leaking 2 1/2-inch diameter essential weld, and identified no problems.

The inspectors reviewed the certifications of the General Electric Level III ultrasonic examiner that performed the sizing of the defect indications in the REC system welds. The examiner was qualified for the activity, with qualifications including Electric Power Research Institute certifications for manual and automated ultrasonic sizing of defects. However, the licensee had approved the use of Procedure GE-UT-104, "Procedure for Manual Ultrasonic Planar Flaw Sizing," Revision 1, and the inspectors noted that the procedure was used for sizing the defect indications in the carbon steel REC system piping welds; however, the stated scope of the procedure was that it was applicable only to austenitic stainless steel piping.

Licensee personnel initiated a condition report, on August 9, 1994, to address this issue and contacted the Electric Power Research Institute Nondestructive Examination Center to verify that the technique used was valid for carbon steel. While the inspectors had no particular concerns in regard to the apparent technical viability of the procedure for use on carbon steels, the failure of the licensee to recognize the scope limitation and formally resolve the matter, prior to performance of sizing, was considered a work control weakness.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

The inspectors observed control room activities on a sampling basis throughout this inspection period. The inspector noted an acceptable level of communication exchange between operators during various control room evolutions, but continued to lack full, complete participation from the entire crew. The lack of rigor appeared to stem from the extended forced shutdown of the plant, with an unknown startup date. Crew briefings continued to emphasize management's concerns to improve the plant and system condition and performance.

The inspectors noted that the operators continued to identify concerns or conditions with plant equipment and structures. Numerous condition reports were initiated by plant operators during their routine shift rounds. The condition reports were not limited to only safety-related systems or equipment, but included balance-of-plant hardware and structures. It appeared that the operators had, and were continuing to make, an effort in identifying deficiencies.

The inspectors observed that the Operations department was continuing to be a more active participant in the daily plant status and planning meetings. Both the oncoming and offgoing shift supervisors attended the daily plant status meetings, which appeared to provide more continuity for the operations department with regard to all plant activities.

4 PLANT SUPPORT ACTIVITIES (71750)

The inspectors reviewed various plant support activities based on observation of work activities, review of records, and tours of the facility. The inspectors noted the following during these evaluations.

4.1 Radiation Protection Controls

The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with regulatory requirements. The inspectors also observed compliance with radiation work permits, proper wearing of protective equipment and personnel

monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to calibration frequency.

Based on the observations made by the inspectors, it appeared that the licensee was implementing an effective radiological protection program.

4.2 Plant Housekeeping

The inspectors observed plant conditions and material/equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled areas were evaluated with respect to controlling the spread of surface and airborne contamination.

On one plant tour, the inspectors noted that the tools for maintenance on the RCIC system were scattered on the floor. No work activity was ongoing and the tools were not properly stored. The inspectors notified the licensee and actions were taken to clean up the area. Other than this one observation, no additional concerns were noted with housekeeping activities.

4.3 Security

The inspectors periodically observed security practices to verify that the licensee's implementation of the security plan was in accordance with site procedures, search equipment at the access control points was appropriately maintained, vital area portals were kept locked and alarmed, and personnel allowed access to the protected area were badged and monitored prior to being granted access to the facility. The inspectors noted no problems in this area during this inspection period.

5 MAINTENANCE OBSERVATIONS (62703)

In March 1993, the licensee installed a new gland sealing system, under Design Change 90-174B, to use clear well water for the main source of sealing water for the SWPs because the old system was difficult to maintain and operate.

One of the challenges of implementing the new design change was how to use unfiltered river water as an alternate source for gland sealing if the clean well source of sealing water was lost. The licensee determined that using cutless rubber bearings with a hard-faced shaft would withstand the use of river water for gland sealing for the required 30 days after a loss-of-coolant accident. As a result, the licensee installed the new bearing and shaft in SWP B. Subsequently, SWPs A, C, and D were provided with the same cutless bearing and a hard-faced shaft.

The service water pumps are on a 24-month preventive maintenance cycle and SWP B had been in service since October 1992. The pump was scheduled for preventive maintenance in October 1994; however, an increase in pump vibration had been noted since May 1994 and, as a result, the pump was on an increased test frequency. On June 25, SWP B vibration readings increased from 0.27 to

0.49 inches per second. This level of vibration was determined by the licensee to be unacceptable and further investigation was initiated. In addition, a review of operating history indicated repeated problems with maintaining flow to the gland sealing system, as noted by condition reports documenting flow conditions of less than 1 gpm.

On September 24, 1994, the licensee initiated a preplanned preventive maintenance inspection of the bearings in SWP B. The work was performed in accordance with MWR 94-0725. During removal of the bearings from SWP B, the cutless rubber bearing near the end of the pump shaft was observed to have the rubber separated from the metal housing and a portion of the rubber was missing.

The licensee also recently installed Design Change 90-174B, Amendment 2, to increase the alarm setpoint from 1 to 2 gpm for indication of low flow to the gland sealing system. This was done as a result of a design review performed by engineering that determined the minimum flow for the SWP gland seals, per the vendor's recommendation, was 1.5 gpm. The licensee was using a value of 0.75 gpm as the gland seal water minimum flow, which the vendor stated was too low.

Following discovery of the degraded bearing, a prompt operability assessment was initiated to document the condition of the other three SWPs. The other three pumps were considered operable due to no apparent significant increases in vibration noted on these pumps. The other three pumps are tested monthly on an increased frequency for vibration due to the potential for high levels of silt in the river water and due to the bearing failure on SWP B.

As a result of the reviews performed by the inspectors, it was noted that: (1) the lack of a resolution of the early indications of potential low flow conditions to the gland sealing system by the licensee contributed to the degradation of the bearing, (2) engineering efforts to determine that the minimum setpoint for indicating low gland sealing water flow were good, and (3) a weakness in the original design change existed since there was no basis for the setpoint value for the minimum gland seal flow that was used.

At the end of this inspection period, the licensee was continuing to evaluate the bearing failure mechanism. The inspectors will continue to review the licensee's efforts to resolve the bearing on the SWPs.

6 SURVEILLANCE OBSERVATIONS (61726)

During this inspection period, surveillance activities were reviewed by a special NRC inspection team. The results of the review are documented in the Special Evaluation Team inspection report.

7 REVIEW OF TEMPORARY INSTRUCTION 2515/125, "FOREIGN MATERIAL EXCLUSION CONTROLS"

During this inspection period, the inspectors performed a review and evaluation to verify that the licensee had implemented effective procedures to prevent foreign material from inadvertently entering safety systems during maintenance activities, outages, and routine operations.

The inspectors reviewed the licensee's procedures for foreign material exclusion. The following procedures contained specific instructions for foreign material exclusion controls:

- Maintenance Work Practice No. 5.1.3, "Foreign Material Exclusion and System Cleanliness," Revision 5
- Conduct of Operations Procedure 2.0.10, "Primary Containment Access Control," Revision 4
- Administrative Procedure 0.24, "Working Over or in Reactor Vessel or Fuel Pool Requirements," Revision 0

The procedure for working over or in the reactor vessel appeared to be adequate to ensure that loose items were not unaccounted for or inadvertently dropped. The procedure for primary containment access appeared to be less specific in that no control point log was referenced in the procedure. The maintenance work practice for foreign material exclusion appeared to be adequate; however, the guidance for when this should be implemented appeared to be too general, as discussed below.

The inspectors performed a review of the licensee's corrective action tracking system to determine the number of occurrences of foreign material in systems during the past year. There were five corrective action items identified for root cause determination and ten work requests for cleanup of maintenance work areas or general plant housekeeping deficiencies.

All of the work requests for cleanup of trash and debris were completed; however, only one of the corrective action deficiencies was closed. The other four corrective action items were scheduled for evaluation and have not been completed.

On October 4, 1994, the inspectors observed reassembly of SWP B after it had been disassembled for scheduled preventive maintenance. During conduct of the work, in accordance with Maintenance Procedure 7.2.15, "Service Water Pump Column Maintenance and Bowl Assembly Replacement," the inspectors reviewed the procedure for references to foreign material exclusion. No reference was found in the procedure, which was an indication that foreign material exclusion controls were not considered.

The inspectors observed the performance of work on SWP B and noted that, during work breaks, the opening in the pump column was left uncovered. This action was discussed with the maintenance manager and supervisor. Both indicated that maintenance procedures were in the process of being upgraded to include foreign material exclusion controls. The maintenance supervisor agreed to reemphasize to work crews the importance of ensuring that foreign materials are not introduced into the service water system.

Based on the reviews performed by the inspectors, it was determined that the licensee had no formal program to ensure that foreign materials were not introduced into systems during the performance of maintenance and modification activities. However, two specialized procedures pertaining to specific work in the fuel pool, reactor vessel, and primary containment contained provisions for maintaining control of work materials.

The instructions that specifically addressed foreign material exclusion controls were used only when requested by a maintenance planner or craft worker; therefore, the implementation of material exclusion requirements was random and without formal controls.

During previous inspection activities in May 1994, the inspectors identified concerns regarding the implementation of the foreign material exclusion program. As a result of these inspection activities, an unresolved item (298/9409-01) was identified, which will require additional review in the near future to resolve the identified discrepancies. The issues identified in this inspection report section will be reviewed during the followup to that unresolved item.

8 ENGINEERING FOLLOWUP (92903)

8.1 EDG Turbocharger Control Air System Operability

A recent design review of the EDGs at Waterford-3 revealed that the turbocharger may not receive adequate lube oil flow upon the loss of control air. Because the CNS has the same model EDGs as does Waterford-3, the inspector assessed the potential for this problem at the CNS.

The diesel system engineer was aware of the Waterford-3 problem through the Cooper-Bessemer (vendor) owners group. The engineer stated that, unlike Waterford-3, the entire diesel air system at the CNS (from the air compressors, through the air receivers, and to the turbocharger lube oil pressure regulator) was classified as a safety-related system. Because of this, the engineer concluded that the air compressors could be relied upon to provide air for system usage during an extended run, such as during a loss of offsite power. Additionally, the engineer stated that the owners group had recently conducted a test on the model of the EDG installed at the CNS and demonstrated that the turbocharger received adequate lube oil flow even without control air.

The inspector reviewed the conclusions provided by the system engineer and agreed that the operability of the turbocharger, and hence the EDG, was not affected by a loss of control air.

8.2 Overspeed of Turbine-Driven Pumps Caused by Governor Valve Stem Binding

On September 19, 1994, the NRC issued Information Notice 94-66, "Overspeed of Turbine-Driven Pumps caused by Governor Valve Stem Binding," which stated that several overspeed trips of the auxiliary feedwater and RCIC system turbine-driven pumps were caused by governor valve stem binding as a result of corrosion forming on the valve stem and causing binding between the stem and packing. Because the corrosion slowed or prevented governor valve movement, the turbines would overspeed when the steam admission valves were opened at startup (governor valve is fully open when the turbine is in the standby condition). In each case, the governor valve stem and/or packing had been replaced within the previous 6 months. The current vendor, Dresser-Rand Steam Turbines, stated that Terry Model ZS and GS turbines were affected by this corrosion. The notice also stated that several industry groups were investigating the cause of the corrosion. The inspector reviewed the licensee's turbine-driven pumps to determine if the pumps were susceptible to this corrosion.

The inspector noted that the RCIC turbine-driven pump had a Terry Model GS turbine. The inspector discussed the potential for stem corrosion governor valve binding with the RCIC system engineer. The engineer was familiar with the information notice but had not performed a detailed evaluation on the potential for stem corrosion binding to occur on the RCIC turbine. The engineer stated that the valve had been functioning normally during surveillance tests for at least 3½ years and that no maintenance had been performed during that period. The inspector questioned the engineer as to whether a formal evaluation would be performed or inspections conducted. The engineer responded that engineering management had not tasked the engineer to perform an evaluation and that management would determine if an evaluation was required and when it would be due. The engineer also stated that a recently developed preventive maintenance task to disassemble and inspect the valve on a refueling basis would be implemented during the next outage.

The inspector questioned the engineer as to whether there were any indications or measurements that were taken during the surveillance tests that would indicate a degradation in valve performance. The engineer stated that the time required to reach rated speed had not increased, which was an indication that the governor valve was operating properly. The inspector asked the engineer if the governor valve was fully open or fully shut while the turbine was in a standby condition and whether the time to reach rated speed was an indication of governor valve performance. The engineer stated that he did not know if the valve was open or shut when the pump was in the standby condition.

The inspector performed a visual inspection of the governor valve stem and packing area. The inspector did not detect any corrosion; however, the

corrosion described by the information notice had occurred between the packing and the stem and may not be apparent from above the packing. The licensee stated that the packing and stem would be inspected from the bottom side of the packing prior to restart from the current unplanned outage.

The inspector concluded that: (1) the licensee probably did not have a stem corrosion binding problem on the RCIC governor valve based on the lack of maintenance since the last disassembly in 1990 (all five of the overspeed incidents described in the notice occurred within a few months of valve stem and/or packing replacement), (2) the system engineer was not aggressive in resolving the status of the RCIC governor valve, and (3) it was apparent that the system engineer was not familiar with his assigned system in that he did not know how the governor valve operated in all modes of operation.

8.3 EDG Jacket Cooling Water System Operability Determination

The inspector reviewed Operability Determination 94-088 for the EDGs, which discussed the use of sodium nitrite as a corrosion inhibitor in the jacket cooling water system. The use of sodium nitrite in the system was a concern because of the system leaks identified in the REC system (see Section 2.2 of this inspection report). The licensee determined that the root cause for REC system leaks was high concentrations of nitrates, which caused intergranular stress corrosion cracking. The licensee evaluated the EDG cooling system to determine if it was susceptible to similar leaks.

The licensee noted that, in all but one of the REC system leaks, the leak originated at a weld that utilized a backing ring. The licensee concluded that the backing ring allowed high concentrations of nitrates to accumulate and accelerate the corrosion process. The licensee contacted the EDG vendor to determine if backing rings had been used in the construction of the cooling system of the EDGs and the vendor stated that backing rings were not used. Additionally, the vendor stated that they were not aware of any weld cracking caused by nitrates in this type of engine.

The licensee analyzed the current chemistry for the EDG cooling water and determined that the system contained very low concentrations of nitrates and that all chemical parameters were well within the specified values. The licensee compared its chemistry requirements to the requirements utilized by other nuclear utilities that have Cooper-Bessemer EDGs. The licensee noted that most other utilities also used some form of nitrite solution for corrosion control in concentrations similar to those used at the CNS. The licensee also noted that most other utilities chemically analyzed the cooling water on a monthly vice a quarterly basis. The licensee stated that they intended to change their sampling frequency to a monthly basis.

The licensee noted that, during each refueling outage, a preventive maintenance task required a complete draining and inspection of the cooling system. Various inspections of the system had not indicated any unusual

corrosion that would be indicative of high nitrate concentrations. The licensee concluded that the periodic draining and refilling would prevent any potential harmful buildup of nitrates.

Based on the reviews performed by the inspector, it was concluded that the EDG jacket water system was satisfactory because of a lack of backing rings, past operating history, and the results of maintenance inspections of the internals of the jacket water system.

8.4 Relief Valve Spring Misapplication

On August 30, 1994, a contractor performing a spare parts review discovered a listing for a relief valve that identified several different part numbers for the relief valve spring. During further investigation of the parts listing, the licensee determined that three relief valves, which had been installed in the field, contained an incorrect spring. The licensee initiated Condition Report 94-0712 to determine the root cause and to initiate corrective actions.

The licensee determined that the three relief valves had been installed with a 500-pound spring; however, documentation had specified a 100-pound spring. The affected relief valves were located in the residual heat removal (RHR), RCIC, and high pressure core injection (HPCI) systems. The licensee noted that, even if the specified 100-pound spring had been installed, it would have been outside the correct range in two of these systems. Additionally, the licensee identified one relief valve that contained a spring that was outside the setpoint range, as indicated by the spring selection chart. In this case, the setpoint was changed from 410 to 450 psig and should have used a larger spring.

The valves in question were Consolidated Type-1970, safety relief valves manufactured by Dresser Industries. The valves were adjustable to a variety of different pressures through the use of a different spring and an adjusting screw. A different spring was specified by the manufacturer for each range of set pressures. Although a valve using a spring outside the specified range can be adjusted to lift at the desired set pressure, other important characteristics such as blowdown and accumulation could be outside the desired range. For example, a 500-pound spring in a 100-pound application would not relieve at rated capacity until the system reached a much higher accumulation pressure. Because of this characteristic, the systems protected by the three relief valves would be vulnerable to damage. The inspector reviewed the licensee's evaluation of the effect that installing the wrong spring in the relief valve had on its associated system.

Based on the evaluations completed by the licensee, the corrective actions centered on the areas of spare parts/inventory control and maintenance activities. The equipment data file and the equipment spare parts listings were not areas contained within the licensee's quality assurance program and the licensee identified several problems in these areas during the evaluation. Additionally, the licensee identified deficiencies in the maintenance program that contributed to the installation of the incorrect springs.

As a short-term corrective action, the licensee initiated MWRs to replace the incorrect springs and to replace nonquality-related components in quality-related applications. The licensee noted that the MWR to replace the springs required that the spring adjustment screw be returned to the original position as per the manufacturer's guidance. However, neither the technical manual nor the MWR required the as-left screw setting, after adjusting the set pressure, to be verified. The as-left setting would have alerted the licensee to the installation of the wrong spring. The licensee also intended to incorporate the spring application chart into procedures for reference to ensure that the spring was correct for the application. Additionally, the licensee began to update the data base to correct known deficiencies identified during this review. As a long-term corrective action, the licensee intended to review and update the equipment database and spare parts listings to be covered by the licensee's quality assurance program.

RCIC Relief Valve RCIC-RV-10RV was sized to protect the suction piping of the RCIC pump from overpressurization due to the thermal expansion caused by a potential open fire. Design basis documentation revealed that the required capacity of the valve was 343 lb/hr. The specified spring (Model A68-90#) was determined to relieve at 1111 lb/hr with a 0.150 inches of lift. At the same set pressure, the installed spring (Model A72-455-555) had a lift of 0.019 inches. The licensee determined that, as installed, Relief Valve RCIC-RV-10RV had a capacity of 247 lb/hr and did not meet the design basis requirements. Appendix R calculations assumed that the RCIC system would be inoperable in case of a fire near the suction piping; however, the probability of such a fire was extremely low. The licensee reviewed the relief valve requirements due to back leakage through the high pressure injection check and isolation valves and determined that the installed valve had the required capacity. Therefore, the licensee concluded that the RCIC system operability was not adversely affected by the installation of the wrong valve spring.

HPCI Relief Valve HPCI-RV-11RV was installed in the nonessential portion of the piping. Although the licensee did not perform a design basis calculation for the required relief capacity of the valve, the licensee conservatively assumed that the capacity was less than required. Because the valve was installed in a nonessential portion of the system, the licensee concluded that the relief valve would not affect the integrity of the essential portions of the HPCI system and, therefore, did not affect the operability of the system.

RHR Relief Valve RHR-RV-17RV was designed to provide protection to the suction piping of the RHR pump due to thermal expansion. The design basis capacity of the valve was determined to be 35 gpm at a set pressure of 150 psi. The licensee determined that the installed spring (Model A72-455-555) had a capacity of 10 gpm at the set pressure. The licensee noted that Relief Valve RHR-RV-17RV was installed parallel to the relief valves for RHR Pumps 1A through 1C (Valves RHR-RV-10RV through -13RV). The licensee determined that the required relief capacity and actual capacity of the valves were 38 gpm and 30 gpm, respectively. The licensee noted that each of the RHR pump relief valves protected the same portions of piping at the same set pressure as Valve RHR-RV-17RV and that the pump isolation valves were normally open. The

licensee concluded that, because the combined relief capacity of Relief Valves RHR-RV-10RV through -13RV exceeded the required capacity, the wrong size spring installed in Valve RHR-RV-17RV did not render the system inoperable. The inspector noted that the relief capacity of any one of the RHR pump relief valves, plus the capacity of Valve RHR-RV-17RV, was greater than the required relief capacity of the that portion of piping. The inspector concluded that this would protect this portion of piping as long as one pump remained unisolated.

RHR Relief Valve RHR-RV-21RV had a setpoint change from 410 psi to 450 psi. This placed the installed relief valve spring outside the range specified by the manufacturer. The licensee contacted the manufacturer on the impact of using the next smaller sized valve spring on the performance of the valve. The manufacturer determined that the valve would have operated satisfactorily with the installed spring.

Overall, the inspector concluded that the licensee had conducted an adequate investigation on the relief valve spring misapplication. Additionally, the inspector concluded that the licensee conducted an appropriate sampling of other equipment with interchangeable parts to ensure that other components did not have the wrong part installed. However, the inspector noted some weaknesses that were not highlighted by the licensee's investigation. For example, the licensee reported that, because past documentation was sometimes incomplete, that the specific root causes could not be determined. The inspector concluded that the licensee's actions should prevent future spring misapplications.

9 FOLLOWUP ON CORRECTIVE ACTIONS FOR A VIOLATION (92702)

9.1 (Closed) Violation 298/9414-02: Use of Inadequate Special Instructions to Perform Check Valve Maintenance

An inspector identified an instance where the licensee failed to provide an adequate special instruction for performance of feedwater check valve maintenance.

In a letter dated August 29, 1994, the licensee acknowledged the violation and stated that the corrective action had been completed for the specific instance cited and that further action to prevent recurrence had been initiated by revision of Maintenance Procedure, 7.2.44.1, "RF Check Valve Maintenance." The inspector reviewed and verified the actions taken by the licensee to address this problem. Based on the reviews performed by the inspector, it appeared that the licensee's actions were appropriate to prevent recurrence.

10 ONSITE REVIEW OF LICENSEE EVENT REPORTS (LER) (92700)

10.1 (Closed) LER 298/93-006: Fire Barrier Doors Discovered Open and Obstructed Without a Continuous Fire Watch

This report documented the discovery that three fire doors to safety-related areas had been left open with no fire watch, as required by Technical Specification 3.19. The licensee determined the cause to be personnel error in all cases. The licensee's immediate corrective actions were to either close the doors or establish fire watches and fire protection requirements were stressed to the individuals responsible. In addition, a roving fire patrol was initiated to ensure that fire door requirements were being met during the refueling outage.

The inspector toured plant areas and observed red diamond labels on fire doors to specify that the door must be closed per Technical Specification requirements. These were very visible and should have minimized the possibility of this event. The inspector concluded that the controls in place at the time were sufficient and that personnel error was the likely cause. However, the licensee revised Administrative Procedure 0.39, "Fire Watches," to specify that fire watch personnel shall not leave the affected area unless relieved. Although the instances documented in this LER did not involve assigned fire watch personnel leaving the area, the procedural changes strengthened the licensee's procedure.

Based on the reviews performed by the inspector, it was verified that the actions taken by the licensee were appropriate to address this issue and to implement actions to prevent recurrence.

10.2 (Closed) LER 298/93-034: Technical Specification Violation Due to Failure to Conduct Required Fire Brigade Training

This report documented the discovery that plant support personnel, who were members of the fire brigade, had not received the required quarterly training. These personnel were receiving their training on a yearly basis. In addition, the licensee discovered that some operations personnel had not received fire brigade training during two consecutive quarters beginning the end of 1992. The licensee determined the cause to be personnel error in the interpretation of fire brigade training requirements. The inspector interviewed training personnel and found that the current method of tracking required fire brigade training was proper.

Based on the reviews performed by the inspector, it appeared that the licensee implemented actions to correct this problem and to prevent recurrence.

10.3 (Closed) LER 298/93-036: Inoperable Technical Specification Fire Doors Without Appropriate Fire Watches Resulting from Personnel Error, Training, and Procedure and Administrative Control Deficiencies

This report concerned the failure to initiate Technical Specification required fire watches when hardware deficiencies were discovered on certain fire doors. The licensee determined the cause of the deficient condition of the fire doors to be inadequate training and inspection criteria. It was determined that no formal training on the inspection procedure was required.

Personnel error and miscommunication was determined to be the cause of the failure to initiate a fire watch after the fire door deficiencies were discovered. The inspector reviewed the licensee's corrective action and found it appropriate. In addition, a random inspection of fire doors throughout the plant did not result in the identification of any fire door deficiencies.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

A. C. Alford, Senior Staff Nuclear Licensing & Safety Engineer
R. L. Beilke, Acting Radiological Manager
J. W. Dutton, Nuclear Training Manager
C. R. Gaines, Events Analysis Manager
R. L. Gardner, Maintenance Manager
J. W. Gausman, Engineering Manager
R. C. Godley, Nuclear Licensing & Safety Manager
H. T. Hitch, Site Services Manager
C. R. Moeller, Technical Staff Manager
J. H. Mueller, Site Manager
R. A. Sessoms, Quality Assurance Division Manager
V. W. Stairs, Assistant Operations Manager

1.2 NRC Personnel

P. H. Harrell, Chief, Project Branch C, Division of Reactor Projects
W. F. Smith, Senior Resident Inspector, River Bend Station

1.3 Other Personnel

R. D. Stoddard, Chief Engineer, Lincoln Electric System

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 October 28, 1994. 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.

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