ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/95-12

License: DPR-46

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

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: August 20 through September 30, 1995

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

Approved: Terrence Reis 10/30/95
T. Reis, Acting Chief, Project Branch C Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite response to an event, operational safety verification, maintenance and surveillance observations, engineering, plant support activities, followup of corrective actions for a violation, followup - operations, and in-office review of licensee event reports (LERs).

Results:

Operations

- Control room staff response to the loss of the 69 kV line demonstrated a high safety awareness. The control room demonstrated good command and control to ensure the electrical distribution system was maintained in an optimum stable condition (Section 3.1).

- Operations response to real and false fire alarms during this inspection report period were rapid and appropriate (Sections 2 and 4.3).

- Operations overrode a nonsafety automatic isolation function for quad sump valve isolation without identifying the need to consult the plant design basis to ensure their actions were bounded by analysis (Section 2).

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- Control room staff failed to document the defeat of a nonsafety-related automatic function in the control room logs. Logkeeping guidance was ambiguous in this area (Section 2).

- The inspector identified that no clear guidance existed to clearly inform the control room staff that the reactor coolant system (RCS) pressure boundary would be inoperable if pressure boundary leakage was identified in the control rod drive system or scram discharge volume outside primary containment. The inspector also identified guidance that indicated continued operation could be acceptable under these conditions. Clear guidance was added to the procedure (Section 3.4).

Maintenance/Surveillance

- A questioning attitude by maintenance personnel identified radioactive contamination on a shipment of scaffolding received as uncontaminated scaffolding from an outside vendor (Section 7.1).

- A maintenance technician failed to initial four steps of a procedure during its use (Section 4.2).

- Additional operations staff were called in to support higher than usual surveillance testing activities. The activities were well managed (Section 5.2).

- The inspectors identified that the surveillance procedure used to perform ASME Code walkdowns of the RCS boundary was known to contain inaccurate code boundaries. The licensee then put the procedure on "Administrative Hold" (Section 5.3).

Engineering

- The Station Operations Review Committee (SORC) rejected several of engineering's operability evaluations for a diesel generator failure. Engineering ultimately produced an evaluation that was acceptable to the SORC (Section 6.2).

- The NRC identified that trouble-shooting guidelines for engineering were nonexistent. Engineering management promptly responded with interim guidelines and efforts to produce final trouble-shooting guidelines (Section 6.1).

Plant Support

- Rapid response and assessment by Radiation Protection (RP) facilitated quick resolution and control of unexpected contamination on two shipments of scaffolding received from an outside vendor (Section 7.1).

- An emergency drill was challenging and illustrated good performance. The emergency drill controller provided insightful feedback of the technical support center (TSC) team's performance (Section 7.2).

- The simulator crew performed well during an emergency drill (Section 7.2).

Management Oversight

- Site management's questioning of operations' overriding an automatic quad sump isolation feature evidenced good involvement and appropriately high standards for the need to validate operating crew actions with respect to design basis assumptions (Section 2).

- Site management effectively questioned inadequate engineering evaluations concerning diesel operability (Section 6.2).

- The licensee did not perform all of the corrective action commitments for a violation. However, the end results of the corrective actions were in place (Section 8).

Summary of Inspection Findings:

Closed Items

- Violation 298/93202-03 (Section 8)
- Inspection Followup Item 298/93201-02 (Section 9.1)
- Inspection Followup Item 298/93202-01 (Section 9.2)
- Inspection Followup Item 298/93202-06 (Section 9.3)
- LER 298/93-025, Revision 0 (Section 10.1)
- LER 298/93-025, Revision 1 (Section 10.2)
- LER 298/93-035, Revision 0 (Section 10.3)
- LER 298/93-035, Revision 1 (Section 10.4)
- LER 298/94-001, Revision 0 (Section 10.5)
- LER 298/94-002, Revision 0 (Section 10.6)
- LER 298/94-002, Revision 1 (Section 10.7)
- LER 298/94-002, Revision 2 (Section 10.8)

- LER 298/94-012, Revision 0 (Section 10.9)
- LER 298/94-012, Revision 1 (Section 10.10)
- LER 298/94-015, Revision 0 (Section 10.11)
- LER 298/94-015, Revision 1 (Section 10.12)
- LER 298/94-015, Revision 2 (Section 10.13)

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was operating at 100 percent power.

From August 21 to September 10, 1995, the plant coasted down to 94 percent power. On September 10, power was reduced to 83 percent to perform turbine valve testing and the control rod pattern was adjusted to an all-rods-out pattern. Power was returned to 96 percent.

End-of-cycle coast down continued through the end of the report period, at which time the plant was at 88 percent of rated power.

2 ONSITE RESPONSE TO EVENTS (93702)

Control Room Response to Fire Alarm

On August 16, 1995, when the Core Spray Pump B was started, the control room received an alarm for the Core Spray Pump B area Fire Detection Zone No. 19. An operator present in the core spray pump room verified that there was no fire and identified that Smoke Detector FP-SD-19-1 had alarmed and would not reset. The shift supervisor determined that the smoke detector was inoperable and entered Technical Specification (TS) Limiting Condition for Operation (LCO) 3.14.B.1, which required that an hourly fire watch patrol be established. The operator initiated Condition Report (CR) 95-0840, which documented the unexpected alarm and started the corrective action process.

The alarm circuit automatically caused the area drain valves to the Reactor Building Floor Drain Sumps A, B, C, and D to close in each quad. The operators overrode the nonsafety-related automatic function and reopened the valves, although there was no guidance which allowed them to defeat this automatic action. Plant management questioned why the valves isolated on a fire alarm and if design basis allowed the operators to reopen the valves and defeat the automatic function. After plant management asked this question, verbal guidance was given to the control room to close the valves and briefly open them every hour to drain the lines until the fire detector was repaired and the alarm signal reset.

From the period when the valves were isolated until guidance was given, the inspectors did not find any documentation that stated the operators had opened the valves and defeated the automatic closure; thus informing follow-on crews that manual action would be required to close the valves. This concern was not documented on CR 95-0840 regarding actions taken due to the fire alarm, nor in the Control Room Log or the Shift Supervisor's Log.

The inspector reviewed the procedure for logkeeping, Procedure 2.0.2, "Operations Logs and Reports," Revision 27, to determine what guidance was available in this instance. The only guidance which may have been considered applicable to this case was a statement that information of historic value or other items that would be necessary to provide adequate information to the following shifts should be included in control room logs. In discussions with the inspector, the Operations Manager stated that instances of overriding a nonsafety-related automatic function would be expected to be logged in control room logs. The logkeeping procedure had been identified as needing better clarification of management expectations and had been included in a program for future review. Since: (1) no other instances of logkeeping concerns had been identified; (2) management had identified this as an area of review; (3) this particular example received prompt management attention; and (4) this instance was of minor safety significance, no further inspector involvement or NRC action was considered necessary regarding logkeeping.

After the inspectors had asked if a CR had been written to address the operators' defeating an automatic feature without proper documentation, a CR was written on August 31. The inspectors expressed concern as to whether the requirements to document a CR were being followed and whether, in the absence of a CR, proper long-term corrective actions to instill a high sensitivity in control room staff to ensure actions are consistent with design basis assumptions. The licensee pointed out that the prompt and intrusive response by licensee management indicated clear expectations in this area and that proper sensitivity by control room staff would result from this instance. The licensee's actions were appropriate to the circumstances, given the equipment manipulated by the operators was not within the scope of the requirements of Appendix B to 10 CFR Part 50.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

On September 13, 1995, the control room received an emergency transformer undervoltage alarm. The operators responded immediately. Alarm Procedure 2.3.2.9, "Panel C - Annunciator C-2," Revision 20.1, was reviewed and the operators performed the action steps of the procedure. As directed by the alarm procedure, the operators entered Abnormal Procedure 2.4.6.3, "Emergency Station Service Transformer Failure/Loss of 69 kV," Revision 16, and followed the action steps listed. The control room supervisor secured all ongoing surveillances, sent a station operator to visually inspect the transformer, and contacted the dispatcher to determine if the 69 kV electrical line was lost. The control room supervisor also conducted a well-organized shift briefing to inform the control room crew what happened and the planned course of action.

The shift supervisor entered TS LCO 3.9.B.1.a, "Incoming Power," which allowed continued operation for 7 days as long as the diesel generators and associated critical buses were demonstrated operable. The investigation into the cause of the alarm determined that a crane located offsite, not associated with the licensee, struck the 69 kV electrical line, resulting in a temporary loss of this line. About 5 hours later, the line was re-energized and the TS LCO action statement was exited.

3.2 Plant Tours

The inspectors toured the plant on a routine basis, and found the plant housekeeping was good despite the outage preparations that were ongoing. The few minor housekeeping issues were brought to the attention of the shift supervisor who immediately took appropriate actions.

3.3 Station Operator Tour

On September 15, 1995, the inspector accompanied the reactor building operator while conducting his plant tour. The operator used Attachment 2, to Procedure 2.1.11, "Station Operator Tour," Revision 68. The operator displayed a good knowledge of plant equipment during discussions with the inspector.

The operator demonstrated good radiological work practices when entering and exiting contaminated areas of the plant. For example, he referred to the survey maps posted at the entrance of each contaminated area prior to entry. The operator also performed appropriate housekeeping duties; i.e., cleaning oil off of plant equipment. The operator followed the guidance that was established in Procedure 2.1.11, while performing his tour through the reactor building. The operator appeared to spend appropriate time and attention observing equipment conditions in each area and then exited the areas to minimize his radiation exposure. Overall, the inspector concluded that the operator was knowledgeable of plant equipment, current conditions of the plant, and the requirements of the procedure. The inspector concluded that the tour was properly implemented.

3.4 Operator Guidance for RCS Pressure Boundary Leakage

The inspector reviewed guidance to operators for RCS pressure boundary leakage. Since the containment atmosphere is inert at power, the RCS leakage in containment is monitored by the licensee's TS leakage limits. Those limits appeared to be implemented appropriately by operations procedures. However, the inspector noted that, in the event RCS boundary leakage was noted outside of primary containment in the control rod drive piping or scram discharge volume, no clear guidance existed to promptly inform operators that the RCS pressure boundary was inoperable in accordance with ASME Code guidelines and that a TS plant shutdown was required. Interviews with operators indicated that operators would immediately initiate a CR and recognize that an operability evaluation was required if RCS pressure boundary leakage was occurring. However, the immediate need to shut down the plant due to inoperable RCS boundary was not made clear.

The inspector noted that, during simulator training, operators were taught that, upon discovery of RCS pressure boundary leakage outside of primary containment, a plant shutdown was required. However, Procedure 2.4.2.1.2, "Small Leaks Outside Primary Containment," implied that, for any leakage outside containment, operators could continue operation as long as the feedwater could keep up with the leakage rate and equipment was not damaged by the leakage. The procedural guidance did not differentiate between pressure boundary leakage and leakage at mechanical connections. Therefore, the inspector considered that, although training guidance was clear that a plant shutdown would be necessary, procedural guidance was ambiguous and could mislead the operator into thinking that an immediate shutdown may not be required in the case of small leakage through the RCS boundary wall outside of primary containment.

The inspector expressed concern that, although it was likely a CR would be written promptly, the need to shut down the plant promptly in accordance with TS requirements associated with inoperable RCS boundary may not be implemented due to the ambiguity in Procedure 2.4.2.1.2.

Based on these discussions, the licensee evaluated the procedural guidance available and determined that resolution of the ambiguity which appeared to allow continued operation in the event of RCS pressure boundary leakage was desirable. A procedure revision was issued to provide this guidance. This action was appropriate to the circumstances.

3.5 Review of Routine Assessment by Institute of Nuclear Power Operations (INPO)

The inspector reviewed the assessment of licensee operations conducted by INPO during 1995. The INPO review did not substantially deviate from the most recent NRC perception of the licensee's performance. No regional follow-up is planned.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Maintenance Test on 24 Volt Battery System

On September 11, 1995, the inspectors witnessed electricians performing maintenance work request (MWR) 95-2851 in accordance with Procedure 7.3.31, "24 Volt Battery Intercell Connection Testing and Maintenance," Revision 3. The electricians performed this maintenance activity to verify that the intercell connections for Batteries 1B1 and 1B2 had not become loose or corroded.

The electricians utilized good communication and self-checking techniques. Because the noise levels in the room were high, the electricians used loud clear voices when communicating to each other, and repeat-backs to confirm what they had heard was correct. Both electricians went beyond the procedure guidance and double-checked each other to verify that the measurement was from the correct intercell connections.

All measurements were found to be within the acceptance criteria and the inspector did not observe any problems during the activity.

4.2 Failure to Initial Procedure Steps for Operation of Reactor Building Air-Lock Doors

On September 20, 1995, during a routine plant tour the inspectors identified that four steps of Procedure 7.0.10, "Railroad Airlock Door Operations," Revision 6 had not been initialed. The inspector pointed this out to the maintenance technician, who stopped his activities and contacted his foreman for resolution. The section of the procedure that was not initialed had been performed by a different technician.

The licensee determined that the steps which were not initialed were either not applicable or had been performed. The step which had been performed, but not signed-off, involved inspection of a seal on the outer reactor building door. The inspectors had observed the seal immediately upon identifying the blank steps in the procedure and the seal appeared appropriate.

Licensee management acknowledged the concern that steps of procedures designated "Continuous Use" must be initialed as the steps are completed. The licensee acknowledged that greater emphasis was needed to ensure technicians understood these expectations. Licensee management conducted meetings with all maintenance technicians to re-emphasize expectations for proper procedure performance in light of these findings. This administrative error, identified by the NRC, is of minimal safety significance.

4.3 Small Equipment Fire during Maintenance Activity

On September 14, 1995, while performing routine preventive maintenance on a nonsafety-related battery charger which supplied power to safety-related isolation functions, the maintenance crew encountered difficulty completing the procedure due to anomalous equipment indications. While resolving the discrepancies, the control room received a fire alarm in that area and responded promptly. A source of smoke was identified near capacitors on the charger, and they were de-energized. This stopped the smoke generation.

The battery was placed on a temporary charger within a few hours and continued to maintain its charge. Maintenance personnel initiated a CR, repaired the charger with new parts, and completed postmaintenance testing. The problem did not recur. The root cause of the failure is being investigated as part of routine plant corrective maintenance program and will be followed by routine inspection activities. The control room and maintenance response to the event appeared appropriate.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 High Pressure Coolant Injection (HPCI) Steam Line Space Temperature Switch Surveillance

On August 30, 1995, the inspector observed portions of Surveillance Procedure 6.2.2.3.2, "HPCI Steam Line Space Temperature Switch Functional Test," Revision 12, which demonstrated operability of temperature switches.

The temperature switches provided a Group 4 isolation signal to the HPCI steam isolation valves to close when the HPCI steam line area temperature reached greater than 200°F.

The operator adhered to the procedure and used good verification techniques when manipulating breakers and switches. The results of the surveillance demonstrated that the temperature switches activated the correct relay to provide an isolation when the acceptance criteria was met.

5.2 HPCI Inservice Test Surveillance

On September 13, 1995, the inspector witnessed operators perform a HPCI test in accordance with Procedure 6.3.3.1.1, "HPCI IST and Quarterly Test Mode Surveillance Operation," Revision 5. Also, the operators performed Special Test Procedure STP-95-112, "HPCI Exhaust Leg Drain Evaluation," Revision 0, to determine the source of water in the exhaust line and to record the quantity of leakage into the exhaust drip leg following surveillance testing.

A briefing was conducted in the control room prior to starting the surveillance. During the briefing, the control room supervisor discussed the expectations for each operator for the surveillance. Operations management was present at the briefing and during portions of the surveillance test.

The operators noted that two unexpected alarms, HPCI Turbine Exhaust Drip Leg Level Hi-Hi and HPCI Steam Line High Flow, were received when the HPCI turbine was started. CR 95-0197 was generated to document these unexpected alarms.

During the surveillance the suppression pool temperature increased to greater than 95°F, which resulted in the shift supervisor entering TS LCO 3.7.d. TS LCO 3.7.d allowed the suppression pool temperature to reach a maximum of 105°F during testing. The maximum temperature reached while performing the surveillance test was 100°F.

The operators followed the surveillance procedure and maintained communications with personnel stationed in the HPCI room throughout the surveillance. The inspector concluded that the surveillance test appeared to be well planned and controlled.

As a result of performing the special test procedure, approximately 1 gallon of water was drained from the exhaust drip leg. This amount was expected. Samples of the drainage were not taken due to the low amount of water found in the drip leg, indicating that an anomalous condition did not exist.

While this surveillance test was being conducted, the control room supervisor brought in an extra shift operator to conduct a fire protection surveillance activity within the control room. The extra licensed operator minimized the distractions associated with coordinating that surveillance activity with the control room personnel conducting the HPCI surveillance.

5.3 Incorrect Code Boundaries Documented in Surveillance Procedure

The inspector reviewed Surveillance Procedure 6.3.10.28, "ASME Required Walkdown of RCS Pressure Boundary," Revision 5.1. This procedure implemented the RCS Pressure walkdown required by the ASME Code at the conclusion of an outage, to ensure RCS pressure boundary operability. The inspector noted that the ASME Code boundary described in the procedure which listed what sections of piping required inspection, were inconsistent with the controlled drawings which also noted ASME Code boundaries. The licensee stated that these boundaries were not consistent because a licensee corrective action for an earlier violation resulted in review of code boundaries and changes to drawings to meet code requirements. The licensee stated that, in the past outage, inspections of the piping newly-identified as Class 1 and Class 2 required inspection, but had not been inspected, except the sections which had piping breaks or repairs during the outage. The licensee pointed out that this was an appropriate level of inspection, since the corrective action to revise the code boundaries had been implemented before the corrective action deadline of October 1994, and complete inspection of the boundaries was not required by licensee's commitments until the refueling outage after October 1994. The inspector, therefore, considered this adequate to meet the licensee's commitments for inspection of piping. However, the inspector noted that the surveillance procedure incorrectly identified the system code boundaries.

The safety significance of this finding is minimal in that the ASME Code walkdown for the upcoming outage will be implemented by a special test procedure for the 10-year inservice inspection ASME Code walkdown and was based on revised drawings. Therefore, Procedure 6.3.10.28 would not be used, even as a reference. Further, the licensee program requires that this particular procedure be revised to include additional ASME Code requirements prior to the following outage.

In response to this finding, the licensee placed the procedure on "Administrative Hold," in accordance with Procedure 0.4, "Procedure Change Process," Revision 22, Section 8.8, and investigated to determine if other procedures of documents had this deficiency. None were identified.

6 ONSITE ENGINEERING (37551)

6.1 Lack of Engineering Trouble-Shooting Guidelines

Licensee engineers attempted to determine the speed of a recirculation pump speed monitor using a hand-held tachometer as a measuring device. During this measurement process, control room operators noted that the recirculation pump speed increased by 2 to 3 percent, causing reactor power to increase by 1 to 1 1/2 percent over a 5-minute period. Operators immediately locked the speed of the recirculation motor generator set and attempted to find the cause of the problem. Engineers performing the trouble-shooting pointed out that the vendor had provided guidance indicating that no adverse effects were likely from obtaining this measurement. Engineering concluded that the process had altered the motor generator set speed control signal, despite vendor manual information.

The NRC inspector questioned why the engineers did not appear to be using trouble-shooting guidelines to assist in systematic trouble-shooting of equipment which could cause changes in reactivity. The inspector noted that the only trouble-shooting procedure in the plant appeared to be a maintenance trouble-shooting procedure, which implied that only maintenance personnel could perform trouble-shooting. This was discussed with engineering.

Engineering management concluded that the lack of engineering trouble-shooting guidelines was not appropriate and, as an interim measure, determined that the maintenance trouble-shooting guidelines would be used by engineering until engineering guidelines could be developed.

The safety significance of these activities was low in that the motor generator set maximum speed was limited by a mechanical overspeed setting, which would not have been affected by this change in control signal. Although the speed of the pump was changed, all accident analyses and thermal limits assumed motor generator set maximum speed at mechanical overspeed setpoint to be the most limiting condition. Therefore, this activity and its consequences were of low safety significance. Likewise, since the engineers appeared to have a well-thought-out approach to diagnosing motor generator set speed drift, the lack of trouble-shooting guidelines in this instance did not appear significant. The licensee's corrective action to develop engineering trouble shooting guidelines appeared appropriate.

6.2 Diesel Generator A (DGA) Operability Evaluation

On September 5, 1995, during a routine hourly surveillance, DGA came up to rated speed and voltage. However, 57 seconds later it reduced speed and came to a complete stop. The licensee declared DGA inoperable.

Engineering developed an operability evaluation containing several weaknesses, such as omission of potential failure causes and lack of systematic evaluations. Plant management appropriately returned it to engineering to correct omissions and to perform further systematic evaluation.

A second operability evaluation was produced, which was also determined to be inadequate for similar reasons and returned for further work. The third operability evaluation was reviewed by the Station Operating Review Committee (SORC) and disapproved. A fourth operability evaluation was approved by SORC. This activity occurred within the 7-day LCO.

The licensee performed several actions and inspections identified in the operability evaluation to correct potential causes of the DGA failure. However, the ultimate cause of the failure has not been identified to date. The licensee considered this a valid failure of DGA and has increased the testing frequency of DGA until the precise cause of failure can be determined. The inspectors reviewed the SORC-approved operability evaluation and found it to be adequate. This indicated that engineering encountered difficulty in producing an analysis consistent with management's and SORC's expectations, but that the overall process was effective.

7 PLANT SUPPORT ACTIVITIES (71750)

7.1 Radiologically Contaminated Scaffolding Received By Licensee in an Uncontrolled Shipment

On September 12, 1995, as a result of a questioning attitude by a contract utility worker at the licensee's facility, the existence of radioactive contamination on scaffolding, which was shipped to the site as uncontaminated material, was identified. The utility worker quickly informed RP, who quickly responded to assess the level of contamination on the material and to set up a radiologically controlled area around the scaffolding. RP determined that the scaffolding contained fixed contamination at maximum levels of 150,000 dpm/100 cm^2. The RP department immediately informed the vendor who supplied the scaffolding and the carrier who delivered it, as well as the NRC Regional and Headquarters offices. The material had been stored at a decontamination site at a Region II vendor facility.

On September 21 and 27, the licensee identified a second shipment of contaminated scaffolding which was transported to the site as uncontaminated material. The maximum contamination was identified as fixed contamination of 400 counts per minute. No loose contamination was identified. The licensee informed the same individuals and companies of this second delivery as well as the shipper, not associated with the earlier scaffolding, and communicated the finding to the NRC. The vendor who originally decontaminated the scaffolding promptly removed the scaffolding from the licensee facility.

This questioning attitude and subsequent finding and coordination of information through various commercial firms, state, and federal agencies as well as the NRC, was an example of outstanding performance by the contract utility worker and the licensee RP department.

7.2 Observation of Emergency Drill

On September 11, 1995. the inspectors observed the performance of emergency response personnel during an emergency drill. The response by the control room staff in the simulator was strong. Operators performed proper actions and for a time were following the requirements of five separate emergency procedures. The operators properly balanced conflicting requirements by evaluating requirements of actions in emergency procedures. For example, during the drill, an anticipated transient without a scram (ATWS) was simulated as well as significant release of radioactivity. The emergency procedure for the ATWS required the main steam isolation valves (MSIVs) to remain open. However, the emergency procedure for the minimization of radioactive release required the MSIVs to remain closed. The control room properly judged that, after power was reduced to a very low level, it was appropriate to close the MSIVs because, although the ATWS was not mitigated, the power level was low and stable. The need to preclude radioactive release overrode the need to provide a steam flow path via the MSIVs once low power was achieved.

The inspectors observed that the TSC team had adequate and timely understanding of the event as it developed and maintained communications with the control room.

At the conclusion of the drill, the TSC drill controller facilitated a feedback session in which several minor problems were identified. Many drill participants identified desirable enhancements. During this feedback session, the TSC staff as well as the drill controller provided critical self-assessments, as well as well-focused recommendations for performance enhancements.

The NRC concluded that, if an event were to occur, this TSC staff would have properly managed the event and licensee support teams and provided valid assessments to the control room and emergency operations facility. Also, the TSC director acknowledged his identified weaknesses and addressed them by recommended corrective action. The drill controller stated that the emergency planning program provided lessons learned during drills to all emergency response team personnel, as applicable. These actions appeared appropriate.

8 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS (92702)

(Closed) Violation 298/93202-03: Plant Personnel Failed to Comply With Plant Procedures

An NRC inspection team identified four examples where plant personnel failed to comply with plant procedures. The first example involved using a completed, but open, MWR to perform additional work. The second example involved a craftsman adjusting a pressure indicator to 75.8 kpa when the work instructions said 82.7 kpa. No explanation for the discrepancy was documented by the craftsman. The third example concerned operators' aids not being controlled as required by licensee's procedures. The fourth example involved training personnel who revised training records by overwriting the incorrect information instead of drawing a single line through it and writing the correct entry near the old one, as required by the licensee's procedures.

The licensee addressed the first example by revising their Administrative Procedure 0.40, "Work Control Program," to include a definition of work scope and to provide guidance on when to revise an MWR. Also, Maintenance Procedure 7.0.1.7, "Troubleshooting Plant Equipment," was written to include a definition of trouble-shooting and to provide instructions to follow when performing trouble-shooting activities. The inspector verified that the current revisions (Procedure 0.40 - Revision 2 and Procedure 7.0.1.7 - Revision 0) contained the above changes.

For the second example, the licensee assessed the as-left condition of the pressure indicator and determined it to be within an acceptable tolerance range, counseled the personnel involved on procedure adherence, and conducted tailgate sessions on procedural adherence with the engineering department. The inspector reviewed the engineering assessment and found it to be appropriate. The inspector verified that the engineering department held the tailgate sessions by reviewing the attendance records. Also, the inspector interviewed the system engineer and the two maintenance technicians involved and was able to determine that the engineer had been counseled, but neither maintenance technician was counseled. The maintenance technicians did not remember being counseled, nor was there any documentation to support that they were counseled. The maintenance technicians were able to tell the inspector what they did wrong and how they would have done it differently, in a method consistent with licensee corrective action goals. The inspector concluded that, even though the maintenance technicians were not counseled on this specific issue, management expectations had been conveyed, and the technicians understood procedure adherence.

For the third example, the licensee conducted a plant walkdown to identify and remove any operators' aids not necessary. Also the licensee revised Procedure 3.26.1, "Meter Banding Change Control," to include banding control for instruments in the field, which located expected normal readings by application of green bands on meter faces. The inspector verified that the current Procedure 3.26.1, Revision 4.1, contained instructions for controlling banding requirements in the field. The inspector also performed random checks of plant equipment to verify that the nonrequired operators' aids were removed.

The licensee addressed the fourth example by disciplining the instructor and holding a departmental meeting to emphasize the importance of correctly changing training records. The inspector randomly questioned instructors on how to make a change to records and found the instructors knowledgeable on this subject.

9 FOLLOWUP-OPERATIONS (92901)

9.1 (Closed) Inspector Followup Item 298/93201-02: Limited Guidance on Implementing the Outage Safety Plan

An NRC team inspection observed several instances where guidance was weak or nonexistent in the procedures developed by the Outage and Modification Department.

The licensee developed an Outage Management Desk Guide to provide outage guidance. The inspector reviewed the Outage Management Desk Guide, Revision 1, which appropriately addressed the lack of safety guidance identified by the inspection team.

9.2 (Closed) Inspector Followup Item 298/93202-01: Weakness in Communicating Management's Expectations

This issue involved several instances where management's expectations were not being communicated properly.

The licensee management conducted a meeting with all departments to communicate their expectations to personnel. Since these observations were made, a number of the licensee management staff have changed and several observations of effective implementation of management expectations have been documented in recent inspection reports.

Based on the corrective actions and observations stated above, the inspector concluded that performance in this area has significantly improved and is generally adequate.

9.3 (Closed) Inspector Followup Item 298/93202-06: Lack Of Effective Management Involvement

This issue involved numerous examples where management involvement and a questioning attitude were lacking while assessing plant problems.

Since these examples were documented, a number of the licensee management staff have changed. NRC inspection reports over the past 6 months documented that management oversight and involvement in resolving plant problems has been greatly improved. Based on these observations, the inspector concluded that the licensee management organization has become much more involved in assessing plant problems. Therefore, the significant concern appears to have been corrected.

10 IN-OFFICE REVIEW OF LERs (90712)

The LERs listed below were reviewed by the inspectors and were determined to have met the reporting requirement of 10 CFR 50.73, the reports contained an adequate assessment of the subject events, the causes appeared accurately identified, corrective actions appeared appropriate to the circumstances, the generic applicability was properly considered, and no further regulatory followup was indicated.

10.1 (Closed) LER 298/93-025, Revision 0: Hydrogen/Oxygen Monitoring System Operability Concerns Due to Moisture Accumulation and Sample Pump Reliability

10.2 (Closed) LER 298/93-025, Revision 1: Hydrogen/Oxygen Monitoring System Operability Concerns Due to Moisture Accumulation and Sample Pump Reliability

10.3 (Closed) LER 298/93-035, Revision 0: Both Diesel Generators Declared Inoperable Due to Incorrect Relay Setpoints Resulting from Inadequate Procedure and Implementation of Vendor Recommended Checks

10.4 (Closed) LER 298/93-035, Revision 1: Both Diesel Generators Declared Inoperable Due to Incorrect Relay Setpoints Resulting from Inadequate Procedure and Implementation of Vendor Recommended Checks

10.5 (Closed) LER 298/94-001, Revision 0: Unexpected Opening of the High Pressure Coolant Injection Pump Minimum Flow Valve, an ESF Component, During Surveillance Testing Due to Actuation of the Pump Discharge Pressure Switch

10.6 (Closed) LER 298/94-002, Revision 0: Unexpected Closure of the B Core Spray Pump Minimum Pump Flow Valve, an ESF Component, During Surveillance Testing Due to a Spurious Spike of the Flow Instrument

10.7 (Closed) LER 298/94-002, Revision 1: Unexpected Closure of the B Core Spray Pump Minimum Pump Flow Valve, an ESF Component, During Surveillance Testing Due to a Spurious Spike of the Flow Instrument

10.8 (Closed) LER 298/94-002, Revision 2: Unexpected Cycle of the Core Spray Pump Minimum Pump Flow Valve During MOV and System Operability Testing, Potentially Resulting in Pump Degradation and Loss of System Redundancy

10.9 (Closed) LER 298/94-012, Revision 0: Technical Specification Non-Compliance for the HPCI System Due to Setpoint Discrepancies Associated with the Low Steam Line Pressure Isolation Switches

10.10 (Closed) LER 298/94-012, Revision 1: Technical Specification Noncompliance for the HPCI System Due to Setpoint Discrepancies Associated with the Low Steam Line Pressure Isolation Switches

10.11 (Closed) LER 298/94-015, Revision 0: Excessive Heatup/Cooldown During RPV Stratification Events

10.12 (Closed) LER 298/94-015, Revision 1: Excessive Heatup/Cooldown During RPV Stratification Events

10.13 (Closed) LER 298/94-015, Revision 2: Excessive Heatup/Cooldown During RPV Stratification Events

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. Buman, Design Engineering Manager
J. Dillich, Maintenance Manager
C. Gaines, Event Analysis Manager
R. Gardner, Operations Manager
R. Godley, Licensing Manager
P. Graham, Senior Engineering Manager
J. Hale, Radiological Manager
J. Herron, Plant Manager
J. Mueller, Site Manager
M. Peckham, Senior Manager of Site Support
G. Smith, Acting Quality Assurance Division Manager
B. Victor, Licensing Engineer

1.2 NRC Personnel

R. Hall, Project Manager
T. Reis, Acting Branch Chief

1.3 Others

J. Jeffries, SRAB Member
J. MacKinnon, IAG Chairman
R. Stoddard, Lincoln Electric System On-site Representative
B. Turnbull, MEC Senior Engineering Nuclear Administration

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

2 EXIT MEETING

An exit meeting was conducted on September 21, 1995. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee did express positions on the inspection findings documented in this report, as discussed in the text of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.