APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-298/93-029

License: DPR-46

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

Facility Name: Cooper Nuclear Station

Inspection At: Brownville, Nebraska

Inspection Conducted: November 21, 1993, through January 1, 1994

Inspectors: R. A. Kopriva, Senior Resident Inspector
W. C. Walker, Resident Inspector

Approved: Elmo E Collins for 1/28/94
J. E. Gagliardo, Chief, Project Section C Date

Inspection Summary

Areas Inspected: Routine, announced inspection of onsite response to events, operational safety verification, maintenance observation, surveillance observation, and followup.

Results:

- Operator response to reactor trip December 14, 1993, caused by feedwater transient, was good. Declaration of Notice of Unusual Event was prompt. Review into the cause of the loss of feedwater was thorough (Section 2.1).

- Reactor startup on December 19, 1993, was performed well. Good communications were noted between the operations personnel (Section 2.2).

- Identification of missing restricting orifices in the core spray instrumentation lines by the licensee was good. The review performed to identify any other potentially missing orifices was thorough (Section 2.3).

- The licensee's actions in response to the inoperability of Valve HPCI-MOV-M017 and the lifting of safety relief Valve MS-71FRV were good (Sections 2.4 and 2.5).

- Observation of control room activities indicated good operator performance (Section 3.1).

- Installation and testing of the reactor water level instrumentation backfill modification was executed well. Preplanning and good communications contributed to the good implementation of the design change (Section 3.2).

- The wrong fuse was removed during a surveillance due to operator error. Operations personnel response to correcting the error was well thought out and implemented (Section 5.2).

- The licensee had not been analyzing lubricating oil samples drawn under the preventive maintenance program which were contaminated with radioactive material. A violation was identified for failure to follow procedures for not having oil samples analyzed (Section 6.1).

Summary of Inspection Findings:

- Unresolved Item 298/9328-01 was closed (Section 6.1).

- Violation 298/9329-01 was opened (Section 6.1).

- Unresolved Item 298/9329-02 was opened (Section 2.5).

- Deficiency 298/93202-01 was updated (Section 5.3).

Attachments:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of the inspection period, the plant was operating at full power.

On December 14, 1993, at approximately 1:34 a.m., a partial loss of feedwater event occurred which resulted in a reactor trip on low reactor vessel level. The licensee placed the unit in cold shutdown to permit corrective maintenance activities to be conducted. Also, the reactor vessel level design modification installation was completed.

Reactor startup commenced on December 19 and full power was achieved on December 23.

At the end of the inspection period, the plant continued to operate at full power.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Reactor Scram and Loss of Feedwater

On December 14, 1993, at approximately 1:34 a.m., while operating at full power, the plant experienced a partial loss of feedwater. Seventeen seconds later a reactor trip occurred on low reactor vessel water level. The HPCI and RCIC systems initiated and injected on a low-low reactor vessel water level at approximately -37 inches. The vessel water level quickly began to recover, and the HPCI system was secured approximately 41 seconds into the event. A Notice of Unusual Event was declared at 1:56 a.m. due to the emergency core cooling system actuation and injection into the reactor vessel. The operators stabilized the plant in Hot Shutdown with feedwater being supplied by the condensate system.

The resident inspectors responded to the site to follow the licensee actions on stabilizing the plant in a hot shutdown condition and to pursue the cause of the loss of feedwater. Upon arriving at the site, the inspectors observed the scram recovery being performed by the control room operators and commenced a review of alarm typer printouts and feedwater system flow graphs.

At 4:15 a.m. the licensee terminated the Notice of Unusual Event when the reactor pressure was reduced, the reactor vessel level had been stabilized, and the reactor feedwater (RFP) pumps were secured. The licensee subsequently took the reactor to cold shutdown.

The licensee indicated that the cause of the low water level was a failure of the RFP master controller, which initially caused the RFP turbines to decrease in speed. The RFP A turbine entered a lock and hold mode with a lower than normal speed when the master controller generated a loss of control signal

trip. The RFP B turbine did not receive a loss of control signal trip, due to a higher bias setting, and the turbine did not enter a lock and hold mode. The RFP B turbine did enter the lock and hold mode when it received a reactor vessel level transmitter failure (low level) signal. By this time, the RFP B had dropped to near minimum pump speed, with pump feedwater flow contribution being negligible.

The licensee found that the failure of the RFP master controller had been caused by the failure of two resistors. The resistors are normally energized, 1/2 watt, carbon resistors. The licensee's root cause determination for the failure was age-related degradation from being normally energized. The inspectors reviewed the licensee's findings and discussed with them their corrective action, which was to replace the failed master controller with a spare controller. The inspectors observed the licensee visually inspect the spare unit for degraded components and the performance of the bench test prior to installation. Also, other similar controllers in the HPCI, RCIC, and reactor feedwater systems were inspected for signs of discoloration and degradation of resistors and other components. No additional anomalies were identified. The licensee currently has no plans to periodically inspect the controllers for signs of resistor discoloration that might signal the potential for subsequent failures.

2.2 Core Spray Restricting Orifices

During a documentation review to respond to Nonconformance Report (NCR) 93-162, which related to core spray excess flow Check Valve CS-CV-16BCV, an engineer noted that the instrument line associated with the valve did not contain a restricting orifice as required by the Updated Safety Analysis Report. It was also noted that the instrument line for excess flow Check Valve CS-CV-17BCV did not contain a restricting orifice. The affected instruments were CS-DPIS-43A and -43B, which are core spray line break detection instruments. The licensee checked the isometric drawings of the system, which also indicated an absence of the restricting orifices. A licensee representative was notified of this condition on December 14, 1993.

The plant had experienced a reactor trip earlier that day and was proceeding to cold shutdown. The licensee initiated Deficiency Report 93-264 pertaining to the missing restricting orifices.

In accordance with Updated Safety Analysis Report, Section V, and Technical Specifications, Section 3.7.D, 1/4-inch orifices are required to be installed inside primary containment on instrument lines which connect directly to systems containing fluids, that are connected to the reactor vessel in order to restrict flow in the event of an instrument line break.

Due to the condition of the plant, the licensee was able to enter the primary containment and inspect the core spray instrumentation lines, which resulted in the conclusion that the drawings were correct and that the orifices had not been installed. The inspectors followed the licensee's review for the

missing orifices and questioned a licensee representative about generic implications of the missing orifices.

The licensee's preliminary assessment of the condition concluded that the deficiency may have constituted a condition that resulted in the plant being outside of its design basis. On December 17, the licensee notified the NRC of this condition.

The inspectors reviewed the licensee's actions to install the two missing core spray instrument restricting orifices. A design review was conducted to verify that all other instrumentation lines, which met the criteria for restricting orifices, contained orifices on the applicable drawings. Sixty-seven instrument lines, besides the core spray instrument lines, were identified as requiring restricting orifices and all 67 were shown on Process and Instrumentation Drawings.

The licensee's review of the as-built information indicated that all orifices had previous confirmation of being installed. The licensee concluded from this information that a generic problem did not exist. The licensee subsequently performed a visual inspection of all 67 orifices in the drywell to verify installation. Thirty-eight of the orifices were identified via visual confirmation of identifying information. The remaining 29 orifices were confirmed using ultrasonic examination. The inspectors attended licensee discussions on methods of positive confirmation of the 29 questionable orifices and followed the system engineer's activities during the performance of the examinations.

The inspectors observed portions of the missing orifices installation and the activities associated with the system walkdowns. A review of the licensee's actions to verify the as-built configuration was performed by the inspectors. The inspectors concluded that the licensee aggressively pursued this issue upon identification and performed a thorough review of available information. The installation of missing orifices in the core spray system was completed on December 18, 1993.

2.3 Reactor Startup

On December 19, 1993, at 8:10 p.m., the inspectors observed the licensee commence a reactor startup from cold shutdown. The licensee had completed its forced outage activities, including the vessel level instrumentation backfill design modification.

The reactor achieved criticality at 9:47 p.m. and the generator was synchronized to the grid at 3:09 p.m. on December 20. The inspectors observed good communication between operators, including repeat backs and good communications between the operators in the control room and in the plant.

2.4 Failure of HPCI Suction Valve MO-17 Actuation

On December 20, during performance of Surveillance Procedure 6.2.2.3.14, "HPCI Turbine Trip and Initiation Logic Functional Test," Revision 22, HPCI-MOV-MO-17 failed to stroke. The valve started, stopped, restarted, and stopped again. The licensee then de-energized the valve to support troubleshooting in the as-found condition. A Problem Resolution Team (PRT) was formed with members from engineering and operations to determine the cause of the failure.

The PRT considered corrosion, contamination or pitting of contacts, loose electrical connections, failure of other components in the logic, and inadequate contact pressure during their analysis. Through a process of elimination, attention was focused on Limit Switch LS-4. This switch was physically closed, however, no electrical contact was evident. Burnishing of the contacts was required to restore electrical contact.

The licensee then began to try to recreate the failure, utilizing a spare motor-operated valve (MOV). The PRT found that a single glass fiber (60 micron diameter and less than 0.1 inch long), obtained from certain burnishing tools, placed between the contacts could be used to duplicate the failure. The inspectors observed and discussed these findings with the licensee.

The licensee then reviewed MOV procedures and determined no special controls were provided to minimize exposure of the limit switch contacts to airborne materials such as mineral wool (insulation) strands. Additionally, the procedures did not specify the tool to be used for burnishing of contacts. One tool available for burnishing of contacts is constructed of cemented glass fibers. The electric shop informed the PRT that the use of a glass fiber tool is not preferred, but also not prohibited.

The licensee performed a review of NCRs and maintenance history and identified nine failures at CNS in the last 5 years that were potentially similar to the HPCI MO-17 failure. Five of these involved failures of safety-related MOVs. NCR 90-088 documents a failure due to a fiberglass strand between the contacts. The PRT found that four of the nine failures have occurred during the last 2 years.

The licensee determined that reliability could be improved through improvement of maintenance procedures. MOV procedures that remove the limit switch component cover will be revised to include controls to minimize exposure of the contacts to foreign material. The procedure changes should include specification of the tool to be used for burnishing contacts.

The licensee did not plan to increase or perform additional inspections of MOVs. The PRT concluded that additional inspections have the potential to reintroduce the above described failure mechanism into an otherwise satisfactory component. Based on the PRT's evaluation, if an MOV has been

operating (tested or otherwise used periodically) satisfactorily for several months, it appears that the probability of this type of failure is low.

The inspectors reviewed the licensee's plans to revise MOV procedures to include controls to minimize exposure of contacts to foreign material, specify the tool to be used for burnishing contacts, and issue a Nuclear Network Request on the valve failure mechanism. The inspectors concluded that the licensee appropriately addressed the valve failure.

2.5 Inadvertent Lifting of Safety Relief Valve During Surveillance

On December 28, 1993, during the performance of Surveillance Procedure 6.1.12, "AD Reactor Pressure Permissive Calibration and Functional/Functional and Logic Tests," Revision 12, safety relief Valve MS-71 SERV lifted. At the direction of the Control Room Operator, the Instrumentation and Control Technician performing the surveillance backed out of the procedure and the safety relief valve was closed when the Control Room Operator reset the arming portion of the low-low set logic at Panel 9-3. The safety relief valve was open for approximately 5 minutes and the suppression pool temperature increased from 71°F to 86°F. The residual heat removal system was placed in suppression pool cooling to lower the temperature. The licensee formed a Problem Resolution Team to review and identify the root cause of the event. The inspectors discussed with the PRT their findings, which included: failure to follow the procedure, at least one test button was pressed incorrectly, some verification points in the procedure were inappropriately initialed, proper verification of the correct alarm by the Control Room Operator was not performed, and inattention to detail by control room operators during performance of the surveillance, resulting in a failure to stop the procedure activity, when incorrect annunciation was received in the control room. The PRT determined that the root cause of the event was personnel error. The PRT made recommendations to licensee management to further emphasize the use of self-checking, determine the need for enhanced labeling in the auxiliary relay room, and closer monitoring of the performance of surveillance procedures by control room operators.

The inspectors discussed these recommendations with licensee management and determined that the actions recommended by the PRT were appropriate. The licensee indicated that, due to the number of recent personnel errors causing events, a review was planned to be performed by the operations group to determine any similarities to the events.

The failure to follow procedures is an unresolved item (298/93029-02) pending NRC review of the licensee's corrective actions to address personnel errors.

2.6 Conclusions

The licensee's response to the reactor scram caused by the loss of feedwater was appropriate. Operator communications were good. The review into the root cause of the feedwater transient was thorough, and the corrective actions taken appeared to be adequate.

The licensee's review groups performed in-depth reviews. The identification of the missing core spray restricting orifices proved to be accurate. The site activity pertaining to the missing orifice, and the ensuing review of other systems for similar concerns, was performed well. The system reviews and actual walkdowns confirmed the presence of the other orifices.

The licensee's activities relating to the reactor startup and power accession were performed well. Good communications between operations personnel were noted.

The performance of the PRT review of the HPCI MOV failure was good.

The personnel error identified with the inadvertent lifting of a safety relief valve is a subject of a review team formed by the licensee to review several recent personnel errors. The licensee's review was on going at the end of the inspection period.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 Control Room Observations

On December 14 and 19-23, 1993, the inspectors observed and monitored reactor trip recovery and plant startup activities in the control room. The operating crew performance during the trip recovery was good. The startup was conducted from cold shutdown conditions. The inspectors noted good communications were being used between the operators. Incoming annunciators were promptly attended to. Due to testing of the reactor vessel level instrumentation backfill modification, the reactor startup and power accession were extended, being accomplished in a controlled manner without incident.

During backshift and weekend tours of the control room, the inspectors noted that the operating crews were alert and attentive to the controls.

The inspectors observed other control room activities throughout the inspection period. Communications between the reactor operators were good.

3.2 Level Instrumentation Backfill

During the licensee's forced outage on December 14-19, 1993, the installation of Design Change (DC) 93-076 was completed. The DC had been initiated to address the concern of noncondensible gases in BWR cold reference legs of reactor vessel level instruments identified in Generic Letter 92-04. NRC Bulletin 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," required a hardware modification to correct possible water level errors. The bulletin required the modification to be implemented at the next cold shut down after July 30, 1993, or before start up of a facility if they were in cold shut down on July 30, 1993.

The inspectors observed portions of the DC hardware installation during the licensee's refueling outage May-July 1993. Due to the timing of the plant

startup in July, the DC was not completed at that time. During the forced outage on December 14-19, the reactor had been taken to cold shutdown, and the licensee completed the outstanding work items. The DC work included installation of 3/8-inch tubing, flow controls utilizing a manually operated needle valve, and local flow indication. The work performed during the forced outage included a change out of the 60 micron filters installed by Maintenance Work Request 93-3023 with larger capacity 5 micron filters and replaced the existing needle valves with dual needle valves. These changes were enhancements to the system and had been recommended during a BWR Owners Group meeting in August 1993.

The inspectors observed portions of the system testing during plant startup on December 19-23. The testing was performed at varying reactor power levels. The licensee had performed adequate planning for implementation and testing of the DC. Testing and performance of the DC was good. At the end of the inspection period, system testing had been completed and the system isolated while the licensee performed a recalibration of certain high water level trip instruments.

3.3 Conclusions

Good performance by control room operators was noted during this inspection period. Reactor trip recovery and plant startup were well executed.

The licensee implemented the remaining portion of the reactor vessel level instrumentation backfill design change during their forced outage. The personnel performing the modification were well prepared and knowledgeable in the tasks required to complete the installation of the modification. The inspectors will review the modification package upon completion of the design change.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Repair of Level Switch For Residual Heat Removal (RHR) A Heat Exchanger Steam Drip Leg

On December 26, 1993, the inspectors observed a control room alarming annunciator for RHR A Heat Exchanger Steam Drip Leg High. The inspectors questioned the control room operator on why this alarm would not clear. The alarm indicated that Level Switch MS-LS-101 had actuated, causing the Switch MS-AO-790 bypass valve to open on a high water level and bypass the normal flow path through the steam trap.

Maintenance Work Request (MWR) 93-4566 was issued on December 27 to troubleshoot the problem. The MWR was assigned to the instrumentation and control group because the problem was believed to be with the level switch for the steam drain pot (MS-LS-101). Upon inspection of the level switch, the instrumentation technician found heat shrink insulation partially covering the

ring lugs on the terminal strip inside the switch housing. It was determined that the heat shrink material had been placed on the ring lugs at the manufacturer.

After heat shrink insulation on the lugs was exposed to high heat, the insulation would thin out and the screws holding the ring lugs become loose, causing poor or open connections. The technician removed excess heat shrink from the ring lugs and landed the ring lugs to the terminal strip. The switch was actuated several times to verify that annunciator RHR A Heat Exchanger Steam Drip Leg High and Steam Bypass Valve MS-AO-790 functioned properly.

The inspectors discussed with the system engineer whether similar configurations of this type of switch were in the plant. This was the only application of this specific type of switch identified and the system engineer was in the process of checking their spare switches for heat shrink insulation. The licensee initiated a deficiency report to document and resolve any future problems with these type switches.

During the troubleshooting, good communication was established between the instrumentation technician and the control room. Also radiological controls in the work area were appropriate and properly implemented.

The inspectors verified that the annunciator was no longer alarmed and Valve MS-AO-790 was aligned properly. The inspectors verified the accuracy of the licensee's documentation of the repair effort through a review of the repair records.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 Reactor Core Isolation Cooling System

On December 1, the inspectors observed the performance of Surveillance Procedure 6.3.6.1, "RCIC Monthly Test Mode Surveillance Operation," Revision 30. During the surveillance, the inspectors noted a packing leak from two instrumentation valves, RCIC-V-150 and RCIC-V-143. These were located on the instrument rack at the 881 foot elevation in the northeast quadrant of the reactor building. The inspectors informed the station operator who was locally performing the RCIC test of the leaking valves. The station operator initiated MWRs 93-4265 and 93-4266 to repair the valves.

Good communications were observed between the control room operator and station operators during performance of the surveillance.

The inspectors reviewed the completed procedure documentation to ensure that the acceptance criteria had been met. The pump was determined to have met Technical Specification requirements.

5.2 RHR Control Logic Failure

On December 17, with the plant in cold shutdown, the licensee was performing Surveillance Procedure 6.2.2.4.3, "Core Spray Logic Power Monitor Functional Test." At Step 8.2 of the procedure, the operator was to remove Fuse 14A-F1B located in Cabinet 9-33. The operator actually removed Fuse 10A-F1B, which is located in the same control cabinet but two panels away. The removal of Fuse 10A-F1B deenergized the RHR B control logic. There were no immediate changes to the RHR system lineup. The RHR D Pump, which is part of Loop B of the RHR system, was operating in the shutdown cooling mode. Upon removal of the fuse, the control room received an alarm indicating the loss of the RHR B logic. The shift supervisor instructed the operator not to replace removed Fuse 10A-F1B until a review was performed to evaluate what, if any, system response would take place by reinstalling the fuse. The concern was that reinstalling the fuse and reenergizing the logic may cause the RHR D pump to trip.

The shift supervisor contacted the outage director, the operations outage coordinator, and the Shift Technical Advisor, informing them of the activities. The licensee's actions were to secure the RHR D pump, reinstall the fuse, and restart the RHR pump. These activities were performed satisfactorily. There were no concerns pertaining to the lack of shutdown cooling during the brief time the RHR pumps were secured. Loop B of the RHR system was inoperable for the low pressure coolant injection mode due to the loss of automatic initiation from having the fuse removed, from 12:31 p.m. to 1:26 p.m. The Technical Specifications were met due to the fact that the reactor was shut down at the time and low pressure coolant injection was not required.

The licensee classified the cause of this event as personnel error. As of the end of the inspection period the licensee was still formulating their corrective actions. The licensee had formulated a team to review the activities and to address human performance issues.

5.3 Standby Liquid Control (SLC) System Testing

On December 27, 1993, the inspectors observed the performance of surveillance Procedure 6.3.8.2, "SLC Pump Operability Test," Revision 35. Prior to performance of the surveillance test, the inspectors verified that the suction and discharge paths were properly lined up for Boron injection into the reactor if required.

During the running of the surveillance on the SLC Pump A, vibration was noted in the piping of the test loop. However, when the lineup was changed to Pump B, the vibration was not evident. The inspectors discussed this observation with the system engineer who was present during the surveillance. The system engineer was in the process of submitting an Engineering Work Request, which would add a reducer in the piping before the throttle valve (SLC-23) and included additional supports of the test piping to reduce vibration. Also, the licensee planned to add a platform around the test tank

to allow for easier access to the tank and replace the test tank return line flow indicator (SLC-FI-1) with an indicator having readings which fall within midrange of the flow indicator scale. The present flow indicator reads at the high end of the scale. The method of adding boron to the SLC tank has been to climb to the top of the tank and add boron. This will be eliminated and the mixing tank, which is already in place, will be used for addition of boron. These modifications are tentatively planned for the next scheduled maintenance outage in early 1995.

During the performance of the surveillance, the inspectors independently verified that all acceptance criteria for both SLC pumps were met and that the vibration instrument used for taking pump vibration readings was within its current calibration cycle. Also, Temporary Procedure Change Notice 93-321 was used to provide more specific instruction for filling of the test tank and performing certain valve manipulations. This Temporary Procedure Change Notice went into effect on November 2, 1993, which addressed a concern raised by the NRC Operational Safety Team (Deficiency 298/93202-01).

The inspectors identified that the pump discharge header drain shutoff valve (SLC-V-20) was leaking during performance of the surveillance. The system engineer initiated a work item to have maintenance repair the valve and a Deficiency Report was written to document the condition.

5.4 Conclusions

The RCIC surveillance was performed well, and communications were good. The inspectors identified two leaking valves which were brought to the attention of the station operator who initiated the appropriate MWR's to correct the problem.

The personnel error identified with the removal of the wrong fuse during the core spray logic test was immediately acted upon by the shift supervisor and the appropriate precautions were taken correcting the error. This event is being reviewed by the license's team along with the item identified in Section 2.5 of this report to address human performance items.

6 FOLLOWUP (92701)

6.1 Failure to Analyze Lube Oil Samples

On September 23, 1993, the licensee caution-tagged Reactor Water Cleanup (RWCU) Pump B due to discoloration of the pump lube oil. RWCU Pump A failed on October 21, and RWCU Pump B failed on October 28. Due to the two pump failures, a PRT was formed to analyze the cause of the pump failures. The inspectors found that some lube oil samples were not being sent out for analysis. The licensee had difficulty locating a laboratory to analyze radioactive samples and, consequently, had six RCIC system lube oil samples, three RWCU oil samples, and four radioactive waste compactor oil samples which had not been sent out for analysis in the past year. The inspectors had identified this as an unresolved item in NRC Inspection Report 50-298/93-28.

The inspectors discussed this issue with the maintenance engineer responsible for lube oil sampling and analysis for wear products. The maintenance engineer provided information on the lube oil sampling program and the inspectors discussed Procedures 7.0.4, "Conduct of Maintenance," and 7.0.9, "Lube Oil Sampling," which specify the requirements for lube oil sampling as part of the Preventive Maintenance Program. Station Procedure 7.0.4, Step 8.4.1, states that lube oil samples taken from rotating equipment are analyzed for wear products and the results are sent to the system engineer for review and trending.

The inspectors found that six lube oil samples from safety-related equipment (RCIC) had not been sent out for analysis.

This was a failure to comply with Procedures 7.0.4 and 7.0.9, which require lube oil samples to be taken from the RCIC system and sent to a laboratory for analysis. Upon receipt of the analysis, the maintenance engineers were to review the results for immediate equipment/operability issues. The licensee failed to follow Procedure 7.0.4, "Conduct of Maintenance," in that lube oil samples taken from safety-related equipment were not sent out for analysis of wear products and, consequently, no system engineer review and trending was possible. This is a violation (298/93029-01) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," which states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Unresolved Item 298/9328-01 is closed.

6.2 HPCI System Testing

On November 24, 1993, the inspectors observed the performance of Surveillance Procedure 6.3.3.1.1, "HPCI IST and Quarterly Test Mode Surveillance Operation," Revision 2. The HPCI pump was on an increased frequency for vibration testing of the pump. During the performance of the surveillance, the system engineer was trying to determine the cause of the increased vibration. An analysis of the vibration data indicated that the high vibration was caused by the incorrect mounting of the vibration instrumentation, causing a false high vibration, and that the actual vibration of the HPCI pump was acceptable.

Also, during performance of the surveillance, the inspectors were in the control room when a station operator in the HPCI room reported an inability the perform Step 8.54 of the procedure. This step required the operator to check the gland seal condenser blower fan motor and belts for proper operation. The operator was unable to check the belts on the blower because there are none, due to the fact that it is a direct drive blower. This was documented as a discrepancy and Temporary Procedure Change Notice 93-340 was issued. The inspectors reviewed several prior months' surveillance procedures to determine whether this discrepancy in Step 8.54 had been previously identified. There was no documentation indicating this discrepancy had been identified prior to this time. The inspectors considered this to be an

example of increased operator sensitivity to identify and document discrepancies in procedures. The licensee is presently reviewing selected maintenance and surveillance procedures for additional issues. However, a commitment to review procedures for technical adequacy has not been made. Licensee management continues to emphasize the importance of documentation of discrepancies during use of procedures and revision of any procedures which are identified as not accurate.

The inspectors reviewed the data for the HPCI surveillance and determined that the acceptance criteria had been met.

6.3 Steam Jet Air Ejectors

On December 20, 1993, the inspectors observed various portions of the plant startup. During observation of the operator actions to secure the mechanical vacuum pumps and start the steam jet air ejector, there appeared to be some confusion between the operators. General Operating Procedure 2.1.1, "Startup Procedure," specified that at a reactor pressure of 500 psig the mechanical vacuum pumps are to be secured and the steam jet air ejector pump is to be started. Upon performing this step, the operators were referred to System Procedure 2.2.55, "Main Condenser Gas Removal System," for starting of the steam jet air ejector pump. This procedure stated that an approximate value of 300 psig should be seen at the outlet of the steam jet air ejectors when the reactor is at 500 psig. The operators were observing approximately 220 psig at the ejector outlets. The inspectors discussed this with the system engineer and reactor operators. The system engineer determined that a reactor pressure of approximately 700 psig would be required to observe a pressure of 300 psig at the steam jet air ejector outlets. The licensee planned to initiate a procedure change notice which would better define the pressure relationships between the reactor and the steam jet air ejectors.

6.4 Conclusions

Further review of the licensee's activities pertaining to oil sampling and procedure requirements for sample analysis results revealed that the licensee had failed to follow their procedures. Lubricating oil samples on some safety-related equipment had not been analyzed during the past year.

Station personnel identified procedures which were incorrect or not clearly understood. Placing the steam jet air ejector in service has been done numerous times in the past but, with the emphasis on accuracy, the operators finally identified a difference between the procedure and actual plant conditions which had been in existence for some time.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

R. L. Belike, Acting Radiological Manager
L. E. Bray, Regulatory Compliance Specialist
R. Brungardt, Operations Manager
R. L. Gardner, Plant Manager
M. D. Hamm, Security Supervisor
H. T. Hitch, Site Services Manager
G. R. Horn, Vice President, Nuclear
R. A. Jansky, Outage and Modifications Manager
J. E. Lynch, Engineering Manager
E. M. Mace, Senior Manager Site Support
J. M. Meacham, Senior Division Manager of Safety Assessment
J. V. Sayer, Acting Technical Assistant
G. E. Smith, Quality Assurance Manager
M. E. Unruh, Maintenance Manager
R. L. Wenzl, NED Site Engineering Manager
V. L. Wolstenholm, Division Manager of Quality Assurance

1.2 NRC Personnel

R. A. Kopriva, Senior Resident Inspector
W. C. Walker, Resident Inspector

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 January 4, 1994. During this meeting, the inspectors reviewed the scope and findings of this report. The licensee acknowledged the findings and did not identify as proprietary any information provided to, or reviewed by, the inspectors.