UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

May 1, 2007

Stewart B. Minahan,
Vice President-Nuclear and CNO
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2007002

Dear Mr. Minahan:

On March 24, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. The enclosed integrated inspection report documents the inspection findings which were discussed on April 5, 2007, with Mr. M. Colomb, General Manager of Plant Operations, and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection three findings were evaluated under the risk significance determination process as having very low safety significance (Green). All three of these findings were determined to be violations of NRC requirements. However, because these violations were of very low safety significance and the issues were entered into your corrective action program, the NRC is treating these findings as noncited violations, consistent with Section VI.A.1 of the NRC's Enforcement Policy. These noncited violations are described in the subject inspection report. If you contest the violations or significance of the violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Cooper Nuclear Station facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,
/RA/

Michael C. Hay, Chief
Project Branch C
Division of Reactor Projects

Docket: 50-298
License: DPR-46

Enclosure: NRC Inspection Report 05000298/2007002
w/Attachment: Supplemental Information

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SUNSI Review Completed: __WCW__ADAMS: X Yes ☐ No Initials: __WCW__
☐ Publicly Available ☒ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive

R:_REACTORS_CNS\2007\CN2007-02RP-SCS.wpd

| RIV:RI:DRP/C | SRI:DRP/C | C:SPE:DRP/C | C:DRS/EB1 | C:DRS/PSB |
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| NHTaylor | SCSchwind | WCWalker | WBJones | MPShannon |
| ***SCS for T-WCW*** | ***E-WCW*** | ***/RA/*** | ***/RA/*** | ***/RA/*** |
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| C:DRS/OB | C:DRS/EB2 | C:DRP/C | | |
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| ATGody | LJSmith | MCHay | | |
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

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|---|---|
| Docket: | 50-298 |
| License: | DPR-46 |
| Report: | 05000298/2007002 |
| Licensee: | Nebraska Public Power District |
| Facility: | Cooper Nuclear Station |
| Location: | P.O. Box 98<br>Brownville, Nebraska |
| Dates: | January 1 through March 24, 2007 |
| Inspectors: | S. Schwind, Senior Resident Inspector<br>N. Taylor, Resident Inspector |
| Approved By: | M. Hay, Branch C, Division of Reactor Projects |

SUMMARY OF FINDINGS

IR 05000298/2007002; 01/01/2007 - 03/24/07; Cooper Nuclear Station: Maintenance Rule, Identification and Resolution of Problems.

The report covered a 3-month period of inspection by resident inspectors and region-based inspectors. Three Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. An NRC identified noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI was identified regarding the licensee’s failure to correct a degraded condition on the safety-related switchgear. Misalignment between the breakers and the switchgear cubicles was documented in multiple condition reports dating back to 2002 but the license failed to correct the condition. As a result of this misalignment, a start-permissive interlock switch in the Service Water Pump D breaker cubicle failed, potentially rendering all four service water booster pumps unavailable during an accident. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-09166.

  The finding is more than minor because it is associated with the Mitigating Systems Cornerstone attribute of equipment performance and affects the associated cornerstone objective to ensure the availability and reliability of systems that respond to initiating events. The Phase 1 Worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because the finding represents an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time. Based on the results of the Phase 2 analysis, the finding is determined to have very low safety significance. The cause of the finding is related to the corrective action component of the crosscutting area of problem identification and resolution in that the licensee failed to correct this degraded condition. (Section 4OA2)

Cornerstone: Initiating Events

- Green. A self revealing noncited violation of Technical Specification 5.4.1(a) was identified regarding the licensee’s failure to establish an adequate maintenance procedure for Reactor Protection System Motor Generator Set B. On November 19, 2006, the voltage regulator failed due to a lack of vendor recommended maintenance on the voltage adjustment potentiometer. This failure resulted in a loss of shutdown cooling. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-09451.

The finding is more than minor because it is associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown conditions. Appendix G, " Shutdown Operations Significance Determination Process," of Manual Chapter 0609 was used to conclude that the finding was of very low safety significance since it did not affect the licensee's ability to monitor core conditions or recover shutdown cooling after it was lost. The cause of the finding is related to the resource component of the human performance crosscutting area in that the licensee did not ensure that complete, accurate, and up-to-date procedures were available for periodic maintenance on the voltage regulator. (Section 1R12)

- Green. A self revealing noncited violation of Technical Specification 5.4.1(a) was identified for licensee's failure to establish adequate operating procedures for filling, venting, draining, and startup of the main steam system. This procedural inadequacy led to a water hammer event on November 21, 2006, resulting in damage to the main steam piping support system. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-09597.

  The finding is more than minor because it is associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because the finding did not contribute to the likelihood that mitigation equipment or functions would not be available following a reactor trip. (Section 4OA2)

## REPORT DETAILS

Summary of Plant Status

The plant began the inspection period at 100 percent power. On January 25, 2007, reactor power was reduced to approximately 56 percent and the reactor coolant system entered single loop operation due to a failure in Reactor Recirculation Motor Generator B which caused it to trip. Full power operation was resumed on January 28 following corrective maintenance on the motor generator. On February 24 reactor power was lowered to 85 percent to facilitate the recovery of a control rod that had been inadvertently mis-positioned. Full power operation resumed on February 25. The plant remained at full power for the remainder of the period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R04 Equipment Alignment

Partial System Walkdown (71111.04)

a. Inspection Scope

The inspectors: (1) walked down portions of the three risk important systems listed below and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's Updated Final Safety Analysis Report (UFSAR) and the licensee's Corrective Action Program (CAP) to ensure problems were being identified and corrected.

- January 24, 2007: Reactor core isolation cooling (RCIC) while the high pressure coolant injection (HPCI) system was inoperable due to a failed surveillance test.
- February 16, 2007: Service Water (SW) Loop B following completion of maintenance on the SW discharge strainer.
- March 6, 2006: Emergency Diesel Generator (EDG) 2 while EDG 1 was inoperable for planned maintenance.

Documents reviewed by the inspectors included:

- System Operating Procedure 2.2.67A, "Reactor Core Isolation Cooling System Component Checklist," Revision 19
- System Operating Procedure 2.2.71, "Service Water System," Revision 92
- System Operating Procedure 2.2.20, "Standby AC Power System (Diesel Generator)," Revision 66

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

Fire Protection Tours (71111.05Q)

a. Inspection Scope

The inspectors walked down the eight plant areas listed below to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional and that access to manual actuators was unobstructed; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features and that the compensatory measures were commensurate with the significance of the deficiency; and (7) reviewed the UFSAR to determine if the licensee identified and corrected fire protection problems.

- January 23, 2007: Zone 21A - Radwaste Building Basement
- January 23, 2007: Zone 21B - Radwaste Building, Elevation 903
- January 23, 2007: Zone 21C - Radwaste Building, Elevation 918
- February 14, 2007: Zone 3E - Reactor water cleanup heat exchanger room
- February 21, 2007: Zone 24 - Multi-purpose facility
- March 5, 2007: Zone 10B - Main control room
- March 6, 2007: Zone 14B Emergency Diesel Generator 1B room
- March 6, 2007: Zone 14D Emergency Diesel Generator 1B Day Tank Room

The inspectors completed eight samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

Flood Protection (Seasonal; External)

a. Inspection Scope

The inspectors: (1) reviewed the UFSAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving external flooding; (2) reviewed the UFSAR and CAP to determine if the licensee identified and corrected flooding problems; (3) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; (4) inventoried the required emergency flood equipment required by plant procedures; and (5) walked down the Missouri River levees within the owner controlled area to verify they had not been modified in such a way as to invalidate the flooding analyses.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors reviewed the licensee's heat exchanger program, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for the EDG 2 jacket water heat exchanger. The inspectors verified that performance tests were satisfactorily conducted for the heat exchanger and reviewed for problems or errors and that the licensee utilized the periodic maintenance method outlined in EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines."

In addition, the inspectors reviewed the licensee's corrective actions regarding a colony of Asiatic clams discovered by the inspectors during observation of maintenance in the service water intake bay.

Documents reviewed by the inspectors included:

- Calculation NEDC 91-239, "DGLO/DGJW/DG Intercooler Heat Exchanger Evaluation," Revision 1
- Emergency Procedure 5.2SW, "Service Water Casualties," Revision 16
- Performance Evaluation Procedure 13.15.1, "Reactor Equipment Cooling Heat Exchanger Performance Analysis," Revision 25
- Condition Report CR-CNS-2007-00559

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a RCIC steam line break and a loss of condenser vacuum. Documents reviewed by the inspectors included Lesson Plan SKL051-51-39.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule (711111.12Q)

a. Inspection Scope

The inspectors reviewed the maintenance effectiveness performance issues listed below to: (1) verify the appropriate handling of structure, system, and component (SSC) performance or condition problems; (2) verify the appropriate handling of degraded SSC functional performance; (3) evaluate the role of work practices and common cause problems; and (4) evaluate the handling of SSC issues reviewed under the requirements of the maintenance rule, 10 CFR Part 50, Appendix B, and the TSs.

- Condition Report CR-CNS-2006-09451, Failure of Reactor Protection System Motor Generator Set B on November 19, 2006

- Condition Report CR-CNS-2006-10643, Failure of Local Power Range Monitor 44-21A, resulting in a half-scram on December 31, 2006

The inspectors completed two samples.

b. Findings

Introduction. A Green self-revealing noncited (NCV) was identified regarding inadequate maintenance procedures for work on a reactor protection system motor-generator set (RPSMG).

Description. On November 19, 2006, RPSMG B experienced a high voltage spike which resulted in its output breaker opening and a loss of power to reactor protection system (RPS) Bus B. The loss of power led to a half-scram and a partial isolation of containment. The plant was in Mode 4 at the time, with shutdown cooling in service using Division 1 of the residual heat removal system. The partial isolation of containment resulted in isolation of the common inboard and outboard shutdown cooling suction Valves (RHR-MO-17 and RHR-MO-18) causing a loss of shutdown cooling. Operators were able to transfer RPS Bus B to its alternate power supply and restore shutdown cooling within 35 minutes. During this time, reactor coolant temperature increased from 99° F to 104° F and the plant remained in Mode 4.

The licensee documented this event in Condition Report CR-CNS-2006-09451 and conducted an apparent cause evaluation. In October 2006, RPSMG B had been overhauled. The work scope included generator refurbishment as well as replacement of the voltage regulator under Work Order 4445148. This work order was completed on October 16, 2006, but only the printed circuit board in the voltage regulator was replaced, not the manual voltage adjustment potentiometer. Subsequent troubleshooting on the voltage regulator determined that this potentiometer had inconsistent end-to-end continuity when rotated. This degraded condition resulted in the voltage regulator erroneously detecting a lower voltage and increased field excitation until the output voltage reached the high voltage trip setpoint for the output breaker. The licensee also concluded that this potentiometer had never been replaced during the life of the plant, nor were there any maintenance activities to periodically clean the voltage regulator.

This RPSMG voltage regulator is a General Electric Model GEK-2400 voltage regulator. The inspectors reviewed the vendor manual for this series of voltage regulator which recommended periodic cleaning of the voltage regulator components to remove dust and dirt and periodic checks for potentiometer end-to-end continuity. Maintenance Plan 800000024631 was created in May 2006 to periodically clean and examine the voltage regulator cabinet using Maintenance Work Practice (MWP) 5.3.5, “Electrical Cabinet Visual Inspection,” Revision 0. The inspectors found that MWP 5.3.5 was a generic inspection procedure which did not include steps that implemented the vendor recommendations regarding the voltage adjustment potentiometer. This maintenance activity was completed in October 2006, in conjunction with the voltage regulator replacement, but the degraded conditions on the potentiometer were not identified. Furthermore, the new voltage regulator installed on October 16, 2006, was shipped from the vendor with a new voltage adjustment potentiometer but the scope of Work Order 4445148 did not address this component so the new potentiometer was not installed.

Following this event, the licensee implemented immediate corrective actions to replace the voltage adjustment potentiometer. Long term corrective actions will include the establishment of a preventive maintenance activity to periodically clean and inspect the potentiometer.

Analysis. The performance deficiency associated with this finding involved the licensee’s failure to provide an adequate maintenance procedure to periodically clean and perform continuity checks on the voltage adjustment potentiometer as recommended by the vendor manual. The finding is more than minor because it is associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown conditions. Specifically, the performance deficiency resulted in a failure of RPSMG B, a partial containment isolation, and the loss of shutdown cooling. Appendix G, " Shutdown Operations Significance Determination Process," of Manual Chapter 0609 was used to conclude that the finding was of very low safety significance since it did not affect the licensee's ability to monitor core conditions or recover shutdown cooling after it was lost.

The cause of the finding is related to the resource component of the human performance crosscutting area in that the licensee did not ensure that complete, accurate, and up-to-date procedures were available for periodic maintenance on the voltage regulator.

Enforcement. Technical Specification 5.4.1(a) requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9 (b), requires the development of procedures for maintenance activities. Contrary to this, Maintenance Plan 800000024631 did not fully implement vendor recommendations for cleaning and inspecting the condition of the voltage adjustment potentiometer. As a result, performance of the potentiometer degraded and caused a failure of the voltage regulator on November 19, 2006, resulting in a loss of shutdown cooling. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-09451, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007002-001, "Inadequate Maintenance Results in a Loss of Shutdown Cooling."

## 1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

### a. Inspection Scope

The inspectors reviewed the four maintenance activities listed below to verify: (1) performance of risk assessments when required by 10 CFR 50.65 (a)(4) and licensee procedures prior to changes in plant configuration for maintenance activities and plant operations; (2) the accuracy, adequacy, and completeness of the information considered in the risk assessment; (3) that the licensee recognized, and/or entered as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) the licensee identified and corrected problems related to maintenance risk assessments.

- January 11, 2007: Planned maintenance on the RCIC system (Work Orders [WO] 4506807 and 4506389)

- January 17, 2007: Emergent work to clean and inspect the SW intake bay sonar system (WO 4548328)

- January 18, 2007: Emergent work to troubleshoot and repair EDG 2 after it failed during surveillance testing (WO 4548656)

- March 13, 2007: Planned maintenance on EDG 2

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the UFSAR and other design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on any TSs; (5) used the Significance Determination Process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has identified and implemented appropriate corrective actions associated with degraded components.

The following equipment performance issues were reviewed:

- Condition Report CR-CNS-2007-00375, Main Steam Line C radiation monitor indication step change on January 16, 2007

- Condition Report CR-CNS-2007-00480, operability of EDG 1 while EDG 2 was inoperable due to a voltage regulator failure on January 18, 2007

- Condition Report CR-CNS-2007-00562, operability of the HPCI turbine following a failure of the overspeed trip reset function to occur within the prescribed surveillance acceptance criteria on January 24, 2007

- Condition Report CR-CNS-2007-00846, operability of the standby liquid control system after a failure of the heat trace on the discharge pipe for the Division 1 and Division 2 pumps on February 5, 2007

- Condition Report CR-CNS-2007-01853, operability of EDG 2 following an intermittent failure of the maintenance lockout switch

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17A)

a. Inspection Scope

The inspectors reviewed Change Notice 11 to Change Evaluation Document 6013140 which installed a like-for-like electronic controller on Service Air Compressor B as well as upgrading the software in the controllers for Service Air Compressors A, B, and C. The inspectors verified that the modification would not have an adverse impact on the availability and reliability of the service air compressors which are important to safety and would not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected four postmaintenance tests associated with the maintenance activities listed below for risk significant systems or components. For each item, the inspectors: (1) reviewed the applicable licensing basis and/or design basis documents to determine the safety functions; (2) evaluated the safety functions that may have been affected by the maintenance activity; and (3) reviewed the test procedure to ensure it adequately tested the safety function that may have been affected. The inspectors either witnessed or reviewed test data to verify that acceptance criteria were met, plant impacts were evaluated, test equipment was calibrated, procedures were followed, jumpers were properly controlled, the test data results were complete and accurate, the test equipment was removed, the system was properly re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the UFSAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- January 30, 2007: WO 4544040 for Tap Changes on the emergency station service transformer
- January 22, 2007: WO 4548656 for replacement of a failed voltage regulator card in EDG 2
- February 8, 2007: WO 4551090 for intrusive inspections of the EDG 2 voltage regulator and installation of test equipment

- February 8, 2007: WO 4557823 for replacement of the maintenance lockout switch on EDG 2

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the five surveillance activities listed below demonstrated that the SSCs tested were capable of performing their intended safety functions. The inspectors either witnessed or reviewed test data to verify that the following significant surveillance test attributes were adequate: (1) preconditioning; (2) evaluation of testing impact on the plant; (3) acceptance criteria; (4) test equipment; (5) procedures; (6) jumper/lifted lead controls; (7) test data; (8) testing frequency and method demonstrated TS operability; (9) test equipment removal; (10) restoration of plant systems; (11) fulfillment of ASME Code requirements; (12) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria were correct; (13) reference setting data; and (14) annunciators and alarms setpoints. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- January 19, 2007: 6.EE.609, “125V/250V Station Battery Intercell Connection Testing,” Revision 10

- January 29, 2007: 6.1DG101, “Diesel Generator 31 Day Operability Test (IST) (DIV 1),” Revision 42

- February 8, 2007: 6.2DG101, “Diesel Generator 31 Day Operability Test (IST) (DIV 2),” Revision 44

- March 5, 2007: 6.HV.104, “Control Room Emergency Fan Charcoal and HEPA Filter Leak Test, Fan Capacity Test, and Charcoal Sampling,” Revision 12

- March 9, 2007: 6.RCIC.102, “RCIC IST and 92 Day Test,” Revision 21

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the UFSAR, plant drawings, procedure requirements, and TSs to ensure that temporary alterations to the standby liquid control heat trace, implemented on February 4, 2007, conformed to these guidance documents and the requirements of 10 CFR 50.59. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's was supported by the test; and (4) verified that appropriate safety evaluations were completed.

b. Findings

No findings of significance were identified.

**Cornerstone: Emergency Preparedness**

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed an emergency preparedness drill conducted on March 8, 2007. The observations were made in the control room simulator and the emergency operations facility and concentrated on the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation. In addition, the inspectors compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying deficiencies. Documents reviewed by the inspectors included:

- Emergency Plan for Cooper Nuclear Station, Revision 51
- Emergency Plan Implementing Procedures for Cooper Nuclear Station
- Emergency Preparedness Drill Scenario for March 8, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

### 4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Initiating Events

The inspectors sampled licensee submittals for the three performance indicators listed below for the period January 1 through December 31, 2006. The definitions and guidance of Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," Revision 4, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of performance indicator (PI) data reported during the assessment period. The inspectors reviewed licensee event reports, monthly operating reports, and operating logs as part of the assessment.

- Unplanned Scrams Per 7,000 Critical Hours
- Unplanned Scrams With Loss Of Normal Heat Removal
- Unplanned Power Changes Per 7,000 Critical Hours

The inspector completed three samples during this inspection.

b. Findings

No findings of significance were identified.

### 4OA2 Identification and Resolution of Problems (71152)

Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors selected the issues listed below for a more in-depth review. The inspectors considered the following during the review of the licensee's actions: (1) complete and accurate identification of the problem in a timely manner; (2) evaluation and disposition of operability/reportability issues; (3) consideration of extent of condition, generic implications, common cause, and previous occurrences; (4) classification and prioritization of the resolution of the problem; (5) identification of root and contributing causes of the problem; (6) identification of corrective actions; and (7) completion of corrective actions in a timely manner.

- Condition Report CR-CNS-2006-09166, Failure of Service Water Pump to Service Water Booster Pump Interlock

- Condition Report CR-CNS-2006-09597, Main Steam Line Water Hammer

The inspectors completed two samples during this inspection.

b. Findings

Inadequate Operating Procedures for Draining Main Steam Lines

Introduction. A Green self-revealing NCV of TS 5.4.1(a) was identified regarding inadequate system operating procedures for draining the main steam system during plant startup. This procedural inadequacy led to a water hammer event on November 21, 2006, resulting in damage to a pipe support on Main Steam Line A in the heater bay.

Description. On November 18, 2006, with the plant operating in Mode 4, operations department personnel inadvertently exceeded the established reactor vessel water level control band of 90 to 110 inches due to an operator error which caused the plant computer to stop displaying real time water level data. Upon subsequent discovery of the error, operators determined that reactor vessel water level had risen above the bottom of the main steam lines (112 inches) and remained there for approximately 30 minutes. It was estimated, based on control rod drive cooling water flow rates at the time, that approximately 1500 gallons of water spilled into the main steam lines during this period.

Operators had several options for draining the main steam line, including the use of low point drains routed to the floor drain system or vacuum draining the water from the steam lines into the condenser. On November 19, 2006, operators attempted to vacuum drain the lines using System Operating Procedure 2.2.56, "Main Steam System," Revision 41. This procedure was chosen over other options due to the fact that a vacuum had been established in the main condenser in order to identify potential condenser tube leaks. Step 5.13 of Procedure 2.2.56 establishes a drain path from the main steam line drains to the main condenser, using main condenser vacuum as the motive force to remove the water. Step 5.6 of Procedure 2.2.56 contains a precaution to "ensure main condenser vacuum is established" prior to draining the main steam lines. This precaution does not, however, quantify the amount of vacuum required to pull water through the steam drain piping to the main condenser. Following completion of this evolution, operators continued with plant startup activities.

On November 21, 2006, with reactor coolant temperature near 212 degrees, operators started the main condenser mechanical vacuum pumps in order to draw a vacuum in the main condenser. As vacuum was established in the main condenser (and in the main steam system), water in the reactor began to flash to steam and main steam flow indications began to spike intermittently. This main steam flow spiking was accompanied by reports from the field of water hammer noises from the steam tunnel and heater bay areas. The loud noises were caused by the impingement of entrained water in the steam flow on pipe elbows in the main steam system. The transient lasted for approximately 20 minutes until operations personnel secured the mechanical vacuum pumps and steam flow subsided.

The licensee documented this event in Condition Report CR-CNS-2006-9597 and performed an apparent cause determination which demonstrated that, on November 19 at least sixteen inches of vacuum in the main condenser would have been required to adequately vacuum drain the main steam lines. Plant operating data showed that at the time that the draining evolution was attempted, only fourteen inches of vacuum were present. Due to the inadequate motive force, no water was removed from the main steam line drains during this activity. In addition, the licensee determined that the water hammer resulted in the failure of several welds on the first downstream pipe support on Main Steam Line A in the heater bay. The inadequate precautionary statement in Procedure 2.2.56 led to an unsuccessful attempt to drain the large amount of water present in the main steam lines. When steam flow was later initiated, this water was entrained in the steam flow and impinged on main steam piping elbows, causing the observed water hammer damage.

The licensee implemented immediate corrective actions following this event which included an inspection of all main steam piping for damage, including portions of the system in the drywell. The only damage to the system was the to the previously mentioned pipe support in the heater bay which was also repaired.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to provide adequate instructions for draining the main steam system during plant startup. The finding is more than minor because it is associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the performance deficiency led to a sustained water hammer event on November 21, 2006, resulting in damage to a pipe support on Main Steam Line A in the heater bay. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have a very low safety significance because the finding did not contribute to the likelihood that mitigation equipment or functions would not be available following a reactor trip.

Enforcement. Technical Specification 5.4.1(a) requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 4 (m), requires that instructions for filling, venting, draining and startup of the main steam system for boiling water reactors. Contrary to this, System Operating Procedure 2.2.56, "Main Steam System," Revision 41, did not contain adequate instructions to drain water from the main steam lines during system startup. This led to a water hammer event on November 21, 2006, resulting in damage to the main steam piping support system. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-09597, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007002-002, "Inadequate Operating Procedures for Draining Main Steam Lines."

Failure to Correct Condition Adverse to Quality on Safety-Related 4160 V Switchgear

Introduction. An NRC identified Green NCV was identified regarding the failure to correct a condition adverse to quality on safety-related 4160 V switchgear.

<u>Description</u>. On November 2, 2006, during performance of Surveillance Procedure 15.1SWBP.301, "Service Water Booster Pump Start Interlock Test (Div 1),", Revision 6, SW Booster Pumps A and C failed to start with only SW Pump D in service. The SW pumps and SW booster pumps are interlocked such that at least one SW pump must be running in order to start a SW booster pump. This start-permissive interlock is performed by auxiliary rotary switches in the SW pump breaker cubicles which are mechanically linked to the breakers' operating arm and change states when the breakers change states. The licensee determined that the SW booster pumps failed to start due to a failure of the auxiliary switch associated with SW Pump D. The switch was replaced and the surveillance test was completed successfully. Surveillance Procedure 15.1SWBP.301 was last performed in February 2005 which was also the last time that this auxiliary switch was known to be operable.

The licensee documented this failure in Condition Report CR-CNS-2006-09166 and performed an apparent cause which concluded that the switch failed to perform its function due to an age-related and duty-cycle dependent degradation of the switch contacts. The switch is a General Electric Model SB-1 switch and was more than 14 years old. Forensic tests concluded that the switch was operating within the allowable manufacturer's tolerances and that the failure of the switch to perform its function was likely due to mechanical linkage misalignment caused by circuit breaker misalignment. The licensee further determined that the breaker misalignment resulted in under-travel of the switch during operation, resulting in inadequate switch contact wipe and a buildup of oxide on the contacts which eventually led to the failure on November 2, 2006. Corrective actions included replacement of the switch in the breaker cubicle for all four SW pumps. The licensee intends to establish a periodic maintenance task to inspect the switches for possible degradation due to under-travel.

The licensee stated that the breaker for SW Pump D had been misaligned for many years as evidenced by similar auxiliary switch failures in 1993 and 1998. Following the 1993 failure, the switch contacts were burnished to reduce contact resistance. The breaker was shimmed following the failure in 1998 to correct the under-travel condition; however, the breaker was replaced in 2000 which re-introduced the misalignment. The licensee's procedures for breaker replacement address shimming the breakers to achieve proper alignment but this process is complicated due to the switchgear room floors not being level. In addition to the interlock failure on November 2, 2006, the inspectors reviewed a sample of condition reports written since 2002, documenting failures, damage to switchgear, and other degraded conditions resulting from breaker misalignment. Condition Report CR-CNS-2005-00055 was written on January 5, 2005 to document the uneven floors in the switchgear rooms. This condition report stated that breaker damage was occurring due to the uneven floors which could affect equipment operability and recommended re-leveling the floors. This condition report was closed on March 28, 2005 with no corrective actions taken. There were an additional four condition reports documenting damage to secondary contacts while racking in/out breakers due to the uneven floors as well as three condition reports documenting various other damage to breakers attributed to misalignment and the uneven floors. In all cases, the licensee corrected the degraded conditions on the switchgear but no corrective actions were implemented to address the long term issue of switchgear misalignment.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to correct breaker misalignment issues which is a condition adverse to quality. The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of equipment performance and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because the finding represents an actual loss of safety function of a single train for greater than its TS allowed outage time (30 days). The inspectors performed a Phase 2 analysis using Appendix A, "Technical Basis For At Power Significance Determination Process," of Manual Chapter 0609, "Significance Determination Process," and the Phase 2 worksheets for Cooper Nuclear Station. The inspectors assumed that the duration of the SW booster pump unavailability was approximately 60 hours. This was based on control room logs which were used to estimate the time the plant was in a configuration in which no SW booster pumps would have started following an accident (SW Pump D in standby with EDG 1 unavailable). Additionally, although plant procedures may have addressed the failure of the SW booster pumps, no credit for recovery was used as a bounding assumption. Based on the results of the Phase 2 analysis, the finding is determined to have very low safety significance. These results were validated by a senior reactor analyst.

The cause of the finding is related to the corrective action component of the crosscutting area of problem identification and resolution in that the licensee failed to correct a degraded condition on the safety-related switchgear.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality, such as defective material and nonconformances, are promptly identified and corrected. Contrary to this, the licensee documented multiple degraded conditions and failures of safety-related 4160 V switchgear due to misalignment between the breakers and the breaker cubicles. This documentation dates back as far as 2002 yet the licensee has not taken adequate corrective actions to ensure that safety-related breakers are correctly aligned within the switchgear cubicles. As a result, on November 2, 2006, the auxiliary switch in the breaker cubicle for SW Pump D, which provides a start-permissive interlock for the SW booster pumps, failed, potentially rendering all four SW booster pumps unavailable during an accident. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-09166, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2007002-003, "Failure to Correct Condition Adverse to Quality on Safety-Related 4160 V Switchgear."

4OA5 Other Activities

Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment of Cooper Nuclear Station conducted in September 2006. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

On April 5, 2007, the NRC resident inspectors presented the results of the inspection activities to Mr. S. Minahan and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not disclosed in this inspection report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee Personnel

T. Bahensky, System Engineer
J. Bebb, Security Manager
R. Beilke, Chemistry Manager
V. Bhardwaj, Engineering Support Manager
D. Buman, Systems Engineering Manager
T. Carson, Maintenance Manager
K. Chambliss, Nuclear Safety Assurance Director
J. Christensen, Support General Manager
M. Colomb, Plant Operations General Manager
R. Dyer, Heat Exchanger Program Engineer
J. Dykstra, Electrical Engineering Program Supervisor
T. Erickson, System Engineer
R. Estrada, Corrective Actions Manager
J. Flaherty, Licensing
P. Fleming, Licensing Manager
G. Griffith, Fuels & Reactor Engineering Manager
T. Hottovy, Engineering Director (Acting)
T. Hough, Maintenance Rule Coordinator
G. Kline, Engineering Director
J. Larson, Quality Assurance Supervisor
M. McCormack, Electrical Systems/I&C Engineering Supervisor
E. McCutchen, Regulatory Affairs Senior Licensing Engineer
M. Metzger, System Engineer
S. Minahan, Vice President - Nuclear & Chief Nuclear Officer
A. Mitchell, Design Engineering Manager
B. Murphy, Emergency Preparedness Manager
R. Noon, Root Cause Team Leader, Corrective Actions
A. Sarver, Balance of Plant Engineering Supervisor
T. Shudak, Fire Protection Program Engineer
T. Stevens, Mechanical Engineering Supervisor
K. Thomas, Mechanical Programs Supervisor
J. Waid, Training Manager
D. Willis, Operations Manager

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

| | | |
|---|---|---|
| 05000528/2007002-001 | NCV | Inadequate Maintenance Results in a Loss of Shutdown Cooling |
| 05000528/2007002-002 | NCV | Inadequate Operating Procedures for Draining Main Steam Lines |
| 05000528/2007002-003 | NCV | Failure to Correct Condition Adverse to Quality on Safety-Related 4160 V Switchgear |

## LIST OF ACRONYMS

| | |
|---|---|
| ALARA | as low as reasonably achievable |
| ASME | American Society of Mechanical Engineers |
| CAP | corrective action program |
| CFR | Code of Federal Regulations |
| EDG | emergency diesel generator |
| HPCI | high pressure coolant injection |
| LER | licensee event report |
| NCV | non-cited violation |
| PI | performance indicator |
| RCIC | reactor core isolation cooling |
| RHR | residual heat removal |
| RWCU | reactor water cleanup system |
| SSC | structure, system, and component |
| TSs | Technical Specifications |
| UFSAR | Updated Final Safety Analysis Report |
| WO | Work Order |