UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-4005

May 5, 2006

Randall K. Edington, Vice
President-Nuclear and CNO
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2006002

Dear Mr. Edington:

On March 24, 2006, 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 7, 2006, with Mr. S. Minahan, 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, two findings were evaluated under the risk significance determination process as having very low safety significance (Green). These findings were also 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/

Kriss M. Kennedy, Chief
Project Branch C
Division of Reactor Projects

Docket: 50-298
License: DPR-46

Enclosure:
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w/attachment: Supplemental Information

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RIV:RI:DRP/C	SRI:DRP/C	C:DRS/OB	C:DRS/PSB	
NHTaylor	SCSchwind	ATGody	MPShannon	
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5/4/06	5/4/06	5/5/06		

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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-298
License:	DPR-46
Report:	05000298/2006002
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	January 1 through March 24, 2006
Inspectors:	S. Schwind, Senior Resident Inspector N. Taylor, Resident Inspector P. Elkmann, Emergency Preparedness Inspector
Approved By:	K. Kennedy, Branch C, Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000298/2006002; 01/01/2006 - 03/34/2006; Cooper Nuclear Station. Surveillance Testing, Other Activities.

The report covered a 3-month period of inspection by resident inspectors and a region-based emergency preparedness inspector. Two 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

- A self-revealing noncited violation of Technical Specification 5.4.1.a was identified regarding the failure of operations personnel to follow procedures for testing safety-related undervoltage relays. Specifically, on January 23, 2006, two licensed operators failed to install a jumper correctly while performing Surveillance Test 6.2EE302, "4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2)," Revision 13. This rendered Emergency Diesel Generator 2 and the emergency stations service transformer inoperable. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-00485.

  The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of human 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 (i.e., core damage). Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not represent the loss of a safety function of a single train for greater than its Technical Specification allowed outage time. The cause of the finding is related to the crosscutting element of human performance in that operations personnel failed to follow the surveillance procedure (Section 1R22).

- The NRC identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," regarding the use of unqualified parts in the service water discharge strainers. Specifically, between 1994 and 2004, the mechanical components used in the strainers were classified as nonessential. This contributed to the failure of Service Water Discharge Strainer B on May 30, 2004. The licensee entered this issue into their corrective action program as Condition Report CR-CNS-2004-04050.

  The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of design control and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). 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 also increased the likelihood of a loss of service water which is an initiating event for Cooper Nuclear Station. 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. Based on the results of a Phase 3 analysis, the finding is determined to have very low safety significance. The cause of the finding is related to the crosscutting element of problem identification and resolution in that, following a similar violation documented in NRC Inspection Report 05000298/2003002-05, the licensee had an opportunity to identify and correct this issue prior to the failure of the strainer (Section 4OA5).

B. Licensee-Identified Findings

Violations of very low safety significance, that were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status: The plant began this inspection period at 100 percent reactor power. On February 10, reactor power was reduced to 55 percent to repair a leaking condenser tube. Full power operation resumed on February 13. On February 26, operators manually scrammed the reactor due to the failure of a moisture separator reheating steam valve combined with a high water level in the moisture separator. A reactor startup commenced on February 27 following repairs to the valve and full power operation resumed on March 1. On March 16, reactor power was reduced to 81 percent power due a malfunction in the control system for Reactor Feed Pump A. On March 17, reactor power was further reduced to approximately 60 percent to repair the isolated phase bus duct cooling system and locate a potential fuel leak in the reactor core. Power ascension began on March 19 but was temporarily suspended at 82 percent on March 20 when the station declared a Notice of Unusual Event due to an electrical fire within the protected area. After exiting the NOUE on March 20, power ascension was resumed and the reactor achieved full power on March 21, where it remained until the end of the inspection period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

Partial System Walkdowns

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 corrective action program (CAP) to ensure problems were being identified and corrected.

- February 6, 2006: Reactor Equipment Cooling (REC), Train B
- February 26, 2006: Reactor Coolant System
- March 16, 2006: Reactor Core Isolation Cooling System

Documents reviewed by the inspectors included:

- System Operating Procedure 2.2.67A, “Reactor Core Isolation Cooling System Component Checklist,” Revision 17, dated July 8, 2004.

- System Operating Procedure 2.2A.REC.DIV2, “Reactor Equipment Cooling Water System Component Checklist (DIV 2),” Revision 0, dated November 23, 2004

- Administrative Procedure 0-CNS-OP-110, “Drywell/Steam Tunnel Inspection,” Revision 2, dated September 9, 2005

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Quarterly Inspection (71111.05Q)

a. Inspection Scope

The inspectors walked down the six 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 19, 2006, Fire Zone 7A, Residual Heat Removal Service Water Booster Pump and Service Air Compressor Areas
- January 19, 2006, Fire Zone 8A, Auxiliary Relay Room
- February 6, 2006, Fire Zone 3D, Reactor Water Cleanup Pump Area and Regenerative Heat Exchanger Areas
- February 6, 2006, Fire Zone 4C, Fuel Pool Heat Exchanger, Control Rod Drive Repair Room and Reactor Water Cleanup Areas
- February 26, 2006, Fire Zone 1F, Suppression Pool Area
- March 5, 2006, Fire Zone 1B, Core Spray Pump Room

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

.2 Annual Inspection (71111.05A)

On March 5, 2006, the inspectors observed a fire brigade drill to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) the number of personnel assigned to the fire brigade, (2) use of protective clothing, (3) use of breathing apparatuses, (4) use of fire procedures and declarations of emergency action levels, (5) command of the fire brigade, (6) implementation of prefire strategies and briefs, (7) access routes to the fire and the timeliness of the fire brigade response, (8) establishment of communications, (9) effectiveness of radio communications, (10) placement and use of fire hoses, (11) entry into the fire area, (12) use of firefighting equipment, (13) searches for fire victims and fire propagation, (14) smoke removal, (15) use of prefire plans, (16) adherence to the drill scenario, (17) performance of the postdrill critique, and (18) restoration from the fire drill. The licensee simulated a fire in the cable spreading room.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

Semi-annual Internal Flooding

The inspectors: (1) reviewed the UFSAR, the flooding analysis, and plant procedures to assess seasonal susceptibilities involving internal flooding; (2) reviewed the UFSAR and CAP to determine if the licensee identified and corrected flooding problems; (3) inspected underground bunkers/manholes to verify the adequacy of (a) sump pumps, (b) level alarm circuits, (c) cable splices subject to submergence, and (d) drainage for bunkers/manholes; (4) verified that operator actions for coping with flooding can reasonably achieve the desired outcomes; and (5) walked down the below listed area to verify the adequacy of: (a) equipment seals located below the flood line, (b) floor and wall penetration seals, (c) watertight door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

- March 2, 2006, Reactor Core Isolation Cooling and Core Spray Pump Room

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 licensee programs, verified performance against industry standards, and reviewed critical operating parameters and maintenance records for the Train A REC heat exchanger. The inspectors verified that: (1) performance tests were satisfactorily conducted for the heat exchanger and reviewed for problems or errors; (2) the licensee utilized the periodic maintenance method outlined in Electric Power Research Institute NP-7552, "Heat Exchanger Performance Monitoring Guidelines"; (3) the licensee properly utilized biofouling controls; (4) the licensee's heat exchanger inspections adequately assessed the state of cleanliness of their tubes, and (5) the heat exchanger was correctly categorized under the maintenance rule.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

The inspectors reviewed the two equipment 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 Technical Specifications (TS).

- Control room annunciator multiplexer and computer failures (Condition Report CR-CNS-2006-1813)

- Failure of the Reactor Building Sump B pump controller on January 13, 2006 (Condition Report CR-CNS-2006-0235)

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

Risk Assessment and Management of Risk

The inspectors reviewed the two 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 entered as applicable, the appropriate licensee-established risk category according to the risk assessment results and licensee procedures; and (4) that the licensee identified and corrected problems related to maintenance risk assessments.

- February 1, 2006, service water intake bay sparger repairs (Work Order 4482779)

- March 6, 2006, Emergency Diesel Generator (EDG) 1 preventive maintenance

Emergent Work Control

The inspectors: (1) verified that the licensee performed actions to minimize the probability of initiating events and maintained the functional capability of mitigating systems and barrier integrity systems; (2) verified that emergent work-related activities such as troubleshooting, work planning/scheduling, establishing plant conditions, aligning equipment, tagging, temporary modifications, and equipment restoration did not place the plant in an unacceptable configuration; and (3) reviewed the UFSAR to determine if the licensee identified and corrected risk assessment and emergent work control problems.

- January 24, 2006, EDG 2 control panel wire lug repairs (Work Order 4483943)

- February 1, 2006, Service Water Discharge Strainer A failure (Work Order 4421583)

- February 3, 2006, EDG 1 jacket water leak repair (Work Order 4485961)

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors: (1) observed operator actions in the control room and reviewed operator logs and plant computer data for the events listed below to evaluate operator performance in coping with nonroutine events and transients; (2) verified that operator actions were in accordance with the response required by plant procedures and training; and (3) verified that the licensee has identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the nonroutine evolutions sampled.

- February 26, 2006, manual reactor scram from 70 percent reactor power due to a moisture separator reheater steam valve failure
- March 16, 2006, operator response to a level transient caused by Reactor Feed Pump B transferring to manual
- March 20, 2006, Notice of Unusual Event due to a fire in the protected area

The inspectors completed three samples.

b. Findings

No findings of significance were identified regarding operator response to these events. The cause of the events were still under investigation at the end of the report period.

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 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.

- January 13, 2006, Service Water Booster Pump minimum flow requirements (Condition Report CR-CNS-2005-07188)
- January 24, 2006, EDG 1 and 2 wire lugs improperly terminated (Condition Report CR-CNS-2006-00502)

- February 3, 2006, EDG 1 jacket water leakage (Condition Report CR-CNS-2006-00773)

- February 26, 2006, Electrohydraulic control fluid contamination (Condition Report CR-CNS-2006-01515)

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17A)

a. Inspection Scope

Annual Review

The inspectors reviewed the licensee's plan to modify the intake structure weir wall during normal plant operation. The inspectors verified that the modification would not have an adverse impact on the availability and reliability of the ultimate heat sink and would not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions.

Documents reviewed by the inspectors included:

- Work Order 4418338
- Design Modification 60116551

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the five postmaintenance test 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 realigned, 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.

- December 15, 2005, Service Water Pump C time delay relay replacement (Work Order 4388737)
- February 1, 2005, Service Water Discharge Strainer A motor coupling repairs (Work Order 4421583)
- February 8, 2006, REC Heat Exchanger A cleaning and tube repairs (Work Order 4458117)
- March 5, 2006, Drywell particulate monitor repairs (Work Order 4491028)
- March 17, 2006, EDG 2 mechanical overspeed trip device and electronic governor repairs (Work Order 4494308)

The inspectors completed five 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 four 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) updating of performance indicator (PI) data; (13) engineering evaluations, root causes, and bases for returning tested SSCs not meeting the test acceptance criteria; (14) reference setting data; and (15) setpoints of annunciators and alarms. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- September 13, 2005, Instrument and Controls Procedure 14.15.1, “Jet Pump Flow Instrument Calibration,” Revision 19, dated June 7, 2005

- January 23, 2006, Surveillance Procedure 6.2EE.302, “4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (DIV 2),” Revision 12, dated January 30, 2005

- February 2, 2006, Surveillance Procedure 6.HPCI.201, “HPCI [high pressure coolant injection] Valve Operability Test (IST),” Revision 13, dated January 18, 2005

- March 14, 2006, Surveillance Procedure 6.2CS.101, “Core Spray Test Mode Surveillance Operation (IST)(DIV 2),” Revision 16, date March 6, 2006

The inspectors completed four samples.

b. Findings

Introduction. A self-revealing, Green noncited violation (NCV) of TS 5.4.1 was identified regarding the licensee’s failure to adequately implement a surveillance procedure.

Description. On January 23, 2006, two licensed operators were performing Surveillance Test 6.2EE302, “4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2),” Revision 13. Step 4.131 of this procedure required the installation of a jumper between Terminals ZP-5 and ZP-6 in the cubicle above Breaker SS1G. This step required concurrent verification, meaning that the status of the jumper was to be verified by a second individual while the jumper was being installed. Following this step, the operators were to verify that Relays 27X-1G and 27XX/1G de-energized. The operators installed the jumper using the concurrent verification process; however, the jumper was installed between Terminals ZA-5 and ZA-6. When they did not observe the correct relays de-energize, the operators stopped the procedure and notified the control room of the error. The control room evaluated the error and determined that the jumper had rendered the Emergency Station Service Transformer (ESST) and EDG 2 inoperable. As a result, operators entered a 24-hour shutdown action statement in accordance with TS 3.8.1 for one inoperable offsite power source and one inoperable EDG. Once the impact of the jumper was understood, it was removed, the surveillance test was completed, and the ESST and EDG 2 were declared operable 2 hours later.

The licensee documented this issue in Condition Report CR-CNS-2006-00485 and performed an apparent cause determination. The licensee determined that the cause of this error was a failure to properly use error prevention tools, such as self-checking and peer checking. Corrective actions included additional reenforcement of management expectations for the use of these tools.

Analysis. The performance deficiency associated with this finding involved operations personnel not following procedures. The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of human 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 (i.e., core damage). Using the Manual Chapter 0609, "Significance

Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it did not represent the loss of a safety function of a single train for greater than its TS allowed outage time.

The cause of the finding is related to the crosscutting element of human performance in that the procedures, training, equipment, and other resources required to avoid errors in this task were in place; however, the operators failed to install the jumper on the correct terminals.

Enforcement. TS 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, Section 9.a, requires that maintenance which can affect the performance of safety-related equipment be performed in accordance with written procedures. Surveillance Test 6.2EE302, "4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2)," Revision 13, step 4.131, required a jumper to be installed between Terminals ZP-5 and ZP-6. Contrary to this, on January 23, 2006, operators performing step 4.131 installed the jumper between Terminals ZA-5 and ZA-6, which rendered the ESST and EDG 2 inoperable. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-00485, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2006002-01, "Failure to Follow Procedure Renders Emergency Diesel Generator and One Offsite Power Source Inoperable."

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the UFSAR, plant drawings, procedure requirements, and TSs to ensure that the temporary modifications listed below were properly implemented. The inspectors: (1) verified that the modification did not have an adverse affect on system operability/availability; (2) verified that the installation was consistent with modification documents; (3) ensured that the postinstallation test results were satisfactory and that the impact of the temporary modification on permanently installed SSCs was supported by the test; (4) verified that the modification was identified on control room drawings and that appropriate identification tags were placed on the affected drawings; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that the licensee identified and implemented any needed corrective actions associated with temporary modifications.

- Leak repairs to the Division 1 low pressure coolant injection inboard containment isolation valve (RHR-MOV-25A) (Temporary Configuration Change 4465881)

- Installation of temporary cages on Service Water Pumps A, B, C, and D to support diving operations in the service water intake bay (Temporary Configuration Change 4491055)

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector performed an in-office review of Revision 50 to the Cooper Nuclear Station Emergency Plan and Revision 32 to Emergency Plan Implementing Procedure 5.7.1, "Emergency Classification," both submitted January 31, 2006. These revisions updated the definitions of emergency classifications, defined "Hostile Action," and revised emergency action levels as described in NRC Bulletin 2005-002, "Emergency Preparedness and Response Actions for Security-Based Events."

These revisions were compared to their previous revisions, to the criteria of NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1, to Nuclear Energy Institute (NEI) 99-01, "Methodology for Development of Emergency Action Levels," Revision 2, to NRC Bulletin 2005-002, and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the licensee adequately implemented 10 CFR 50.54(q). This review was not documented in a Safety Evaluation Report and did not constitute approval of licensee changes; therefore, these changes are subject to future inspection.

The inspector completed two samples during this inspection.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

Cornerstone: Initiating Events

a. Inspection Scope

The inspectors sampled licensee submittals for the three PIs listed below for the period January 1, 2004, through December 31, 2005. The definitions and guidance of NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the licensee's basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. The inspectors reviewed licensee event reports (LERs), 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)

.1 Review of Items Entered into the CAP

a. Inspection Scope

The inspectors performed a daily screening of items entered into the licensee's CAP. This assessment was accomplished by reviewing condition reports and work orders and attending corrective action review and work control meetings. The inspectors: (1) verified that equipment, human performance, and program issues were being identified by the licensee at an appropriate threshold and that the issues were entered into the CAP; (2) verified that corrective actions were commensurate with the significance of the issue; and (3) identified conditions that might warrant additional follow-up through other baseline inspection procedures.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In addition to the routine review, the inspectors conducted a more in-depth review of Condition Report CR-CNS-2005-08375, which documented the root cause for a blown control power fuse, which rendered the high pressure coolant injection (HPCI) system inoperable. 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.

b. Findings

No findings of significance were identified. Additional details regarding this equipment failure are discussed in Section 4OA3.

4OA3 Event Follow-up (71153)

(Closed) LER 05000298/2005-005-00: High Pressure Coolant Injection Valve Control Power Fuse Results in Loss of Safety Function

On November 16, 2005, control room operators observed that the position indication lights for the HPCI injection valve (HPCI-MOV-19) were not illuminated. HPCI-MOV-19 is a normal shut valve which opens upon an HPCI initiation signal. After further investigation, the licensee determined that a fuse had blown in the 125 Vdc control circuit. HPCI was declared inoperable until the fuse could be replaced and the valve was verified to operate correctly. The licensee documented this issue in Condition Report CR-CNS-2005-08375 and conducted a root cause investigation which determined that the fuse had failed due to voids in the solder and poor wetting of the solder on the heater element inside the fuse. This was a Bussman FRN-R-1 fuse with a date code of K08. Additional corrective actions included replacement of all fuses of this type with the same date code and a procurement restriction from purchasing additional fuses with this date code. No performance deficiencies were identified during the review of this LER. This LER is closed.

4OA5 Other Activities

(Closed) Unresolved Item (URI) 05000298/2005009-03: Failure to Maintain Design Control of Service Water Discharge Strainers

Introduction. The inspectors identified a Green NCV regarding the licensee's use of unqualified parts in the service water discharge strainers.

Description. NRC Inspection Report 05000298/2005-009 discussed a URI regarding the use of unqualified parts in the safety-related service water discharge strainers. This condition resulted in the failure of Service Water Discharge Strainer B on May 30, 2004. This item remained unresolved pending completion of a Significance Determination Process, Phase 3, analysis. This analysis was completed on February 8, 2006, and concluded that this issue was of very low safety significance.

Analysis. The performance deficiency associated with this finding involved the failure to maintain the design of the service water discharge strainers. The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of design control and affects the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). 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 also increased the likelihood of a loss of service water, which is an initiating event for Cooper Nuclear Station. 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 strainer unavailability was greater than 30 days. Additionally, a recovery credit of 1 was used since the licensee has the ability to bypass a failed service water strainer. The most limiting core damage sequences involved a loss of offsite power with a failure to recover an EDG or offsite power within 4 hours, a transient without the power conversion system and failure of the containment hard piped vent, or a loss of the 4160V Buss 1F and the loss of containment heat removal capability. Based on the results of the Phase 2 analysis, the finding was determined to have substantial safety significance.

A senior reactor analyst performed a Phase 3 analysis and determined that the finding is of very low safety significance. The analyst used the following assumptions in the Cooper SPAR Model, Revision 3.21:

- The defective wiper arm was installed for greater than one year.

- One wiper arm separation event will occur within a one-year period and the separation will disable the strainer, requiring operators to open the strainer bypass valve in order to maintain the function.

- Bypassing the strainer within 45 minutes will not result in a consequential loss of service water.

- The probability that the strainer bypass valves would not be opened within 45 minutes of the wiper arm failure was calculated to be 2.3E-3.

- The deficiency was not considered to have common cause implications because the manufacturing defect that resulted in a mechanical failure of the Train B service water strainer wiper arm was isolated to that component.

The analyst determined that the change in core damage frequency related to this finding was 3.9E-7/yr. Consideration of external events and large early release frequency did not result in a significant increase in the risk associated with this finding. As a result, the finding was determined to be of very low safety significance (Green)

This finding had crosscutting aspects associated with problem identification and resolution. NRC Inspection Report 05000298/2003002 documented a similar issue (NCV 05000298/2003002-05) regarding the installation and use of unqualified electrical parts in the service water discharge strainer controllers. This condition was entered into the licensee's corrective action program as Notification 10218375. The licensee's apparent cause determination and extent of condition evaluation, completed on June 28, 2004, failed to identify the unqualified mechanical components, even though the cause of both qualification issues was the same. The licensee's failure to identify that unqualified parts were installed in the service water strainers during the apparent cause and extent of condition review for the previous violation was determined to reflect current plant performance involving weaknesses in the CAP which result in repetitive problems that impact plant operation.

Enforcement. Title 10 of the Code of Federal Regulations, Part 50, Appendix B, Criterion III, "Design Control," requires that measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the SSCs. Contrary to this, between 1994 and 2004, the wiper arm and other mechanical parts for the service water discharge strainers were classified as nonessential in the procurement system. This resulted in a substandard wiper being installed in Service Water Discharge Strainer B, which subsequently failed on May 30, 2004. The cause of the failure was inadequate adhesive between the metal and rubber components of the wiper arm, which allowed the rubber to become dislodged and caused the strainer to become bound. Corrective actions included replacement of the failed components and the remaining stock of mechanical components were subjected to a commercial grade dedication inspection. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-CNS-2004-04050, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2006002-02, "Failure to Maintain Design Control of Service Water Discharge Strainers."

4OA6 Meetings, Including Exit

On March 24, 2006, the emergency preparedness inspector conducted a telephonic exit meeting to present the inspection results to Mr. J. Roberts, Director, Nuclear Safety Assurance, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On April 7, 2006, the 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 asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- TS 5.4.1.a requires procedures to 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.a, requires procedures for maintenance that can affect the performance of safety-related equipment. Contrary to this, on January 30, 2006, maintenance was performed on Service Water Discharge Strainer A using an inadequate procedure which rendered the strainer inoperable on February 1, 2006. The strainer motor was uncoupled and removed using Maintenance Procedure 7.2.30, "Service Water Zurn Strainer Maintenance," Revision 8; however, this procedure did not provide adequate instructions for recoupling the motor. As a result, the coupling failed on February 1, 2006. This was entered in the licensee's CAP as Condition Report CR-CNS-2006-00789. This finding is of very low safety significance because this condition was identified and corrected before it challenged the operability of the service water system.

- TS 5.4.1.a requires procedures to 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 2.b, requires procedures to be implemented for nuclear plant startup. Nuclear Performance Procedure 10.13, "Control Rod Sequence and Movement Control," Revision 53, Attachment 5, step 15, required that Control Rod 50-23 be withdrawn from Position 04 to Position 08 during reactor startup. Contrary to this, on February 28, 2006, during a reactor startup, operators did not withdraw Control Rod 50-23 in accordance with step 15. This was entered in the licensee's CAP as Condition Report CR-CNS-2006-01579. This finding is of very low safety significance because this condition was identified and corrected before there were any challenges to core thermal limits or fuel cladding integrity.

- TS 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, Section 9.a, requires maintenance that can affect the performance of safety-related equipment be performed in accordance with written procedures. Procedure 14.15.1, "Jet Pump Flow Instrument Calibration," Revision 19, step 3.6, required technicians to obtain the latest gain adjustment factors for the jet pump flow instrument, NBI-(SUM)-76B, as determined from the most recent revision of Procedure 15.RR.302. Contrary to this requirement, technicians failed to obtain the latest gain for NBI-(SUM)-76B when implementing Procedure 14.15.1 on September 13, 2005. This was entered in the licensee's CAP as Condition Report CR-CNS-2006-01207. The finding is of very low safety significance because this condition was identified and corrected before there were any challenges to core thermal limits or fuel cladding integrity.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Bednar, Emergency Preparedness Manager
C. Blair, Engineer, Licensing
D. Cook, Technical Assistant to General Manager
S. Minahan, General Manager of Plant Operations
K. Chambliss, Operations Manager
J. Christensen, General Manager of Support
R. Estrada, Corrective Actions Manager
J. Flaherty, Site Regulatory Liaison
P. Fleming, Licensing Manager
J. Roberts, Director, Nuclear Safety Assurance
R. Shaw, Shift Manager
J. Sumpter, Senior Staff Engineer, Licensing
K. Tanner, Shift Supervisor, Radiation Protection
R. Hayden, Emergency Preparedness Staff
R. Edington, Vice President
S. Blake, Manager, Quality Assurance
K. Fili, Manager, Nuclear Projects
D. Kimbell, Planning, Scheduling & Outage Manager
G. Kline, Director, Engineering
D. Willis, Maintenance Manager
R. Maine, Instrumentation & Control Supervisor
C. Walters, System Engineer
H. Hawkins, Instrumentation & Control Supervisor

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2006002-01	NCV	Failure to Follow Procedure Renders Emergency Diesel Generator and One Offsite Power Source Inoperable (Section 1R22)
05000298/2006002-02	NCV	Failure to Maintain Design Control of Service Water Discharge Strainers (Section 4OA5)

Closed

05000298/2005-005-00	LER	High Pressure Coolant Injection Valve Control Power Fuse Results in Loss of Safety Function (Section 4OA3)

05000298/2005009-03	URI	Failure to Maintain Design Control of Service Water Discharge Strainers (Section 4OA5)

LIST OF ACRONYMS

CAP	corrective action program
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
ESST	emergency station service transformer
HPCI	high pressure coolant injection
IST	inservice testing
LER	licensee event report
NCV	noncited violation
PI	performance indicator
REC	reactor equipment cooling
SSC	structure, system, and component
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item