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

November 7, 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 05000298/2006004

Dear Mr. Edington:

On September 23, 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 October 5, 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, four findings were evaluated under the risk significance determination process as having very low safety significance (Green). All 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/

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

Docket: 50-298
License: DPR-46

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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	C:DRS/EB1
NHTaylor	SCSchwind	RLNease	MPShannon	JAClark
E - KMKennedy	***E - KMKennedy***	***/RA/***	***DAPowers for***	***/RA/***
11/ /06	11/ /06	11/6/06	11/7/06	11/6/06
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket:	50-298
License:	DPR-46
Report:	05000298/2006004
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	June 25 through September 23, 2006
Inspectors:	S. Schwind, Senior Resident Inspector N. Taylor, Resident Inspector J. Hanna, Senior Resident Inspector P. Elkmann, Emergency Preparedness Inspector M. Murphy, Senior Operations Engineer
Approved By:	K. Kennedy, Branch C, Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000298/2006004; 06/25/2006 - 09/23/06; Cooper Nuclear Station. Maintenance Risk Assessments and Emergent Work Evaluation, Operability Evaluations, Identification and Resolution of Problems, Other Activities.

The report covered a 3-month period of inspection by resident inspectors and region-based inspectors. Four 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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

- <u>Green</u>. The NRC identified a noncited violation of 10 CFR 50.65(a)(4) regarding the online risk evaluation for a surveillance test on safety-related undervoltage relays. On August 21, 2006, the licensee performed routine testing of the under-voltage relays for safety-related Bus 1G. The online risk assessment for August 21 reflected this testing but did not consider an increase in the likelihood of a loss of offsite power due to a modification of transmission towers inside the owner controlled area that was occurring at the same time. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-06099.

  The finding affected the Initiating Events Cornerstone and is more than minor because the licensee’s risk assessment failed to consider unusual external conditions that were present during the surveillance test. The finding is not suitable for significance determination process evaluation; however, it has been reviewed by NRC management and was determined to be a finding of very low safety significance. This determination took into consideration the short duration of the work activity and the fact that the relay testing and the transmission modifications were both completed without any adverse consequences. The cause of the finding is related to the crosscutting element of human performance in that the licensee’s work control process did not appropriately incorporate risk insights regarding the transmission system work while planning Bus 1G undervoltage testing. (Section 1R13)

Cornerstone: Mitigating Systems

- <u>Green</u>. The NRC identified a noncited violation of Technical Specification 5.4.1.a regarding the licensee's failure to follow procedures for maintenance affecting the performance of safety-related equipment. Specifically, the inspectors discovered three examples of scaffolding constructed within the minimum separation distance to operable safety-related equipment as defined in Maintenance Procedure 7.0.7, "Scaffolding Construction and Control." The licensee documented the procedural violations in CR-CNS-2006-06763.

The finding affected the Mitigating Systems Cornerstone and is more than minor because, if left uncorrected, the failure to maintain the standards of Procedure 7.0.7 could become a more significant safety concern. 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. This finding has a crosscutting aspect in the area of human performance in that the licensee did not effectively communicate expectations regarding work practices to workers constructing scaffolding or to supervisors who routinely monitor these activities. (Section 1R15)

- Green. The NRC identified a noncited violation of Technical Specification 5.4.1.a regarding the licensee's inadequate procedure for tracking abnormal, off-normal or alarm conditions. On August 11, 2006, during a review of operator work arounds, the inspectors identified that a failed control room annunciator was not being controlled as required by Alarm Procedure 2.3.1, "General Alarm Procedure," Revision 51. The annunciator had been marked with a green flag since June 11, 2006, to indicate that it had failed even though it was still performing its function. The licensee documented the procedural violation in Condition Report CR-CNS-2006-05852 on August 14, 2006.

  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 (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. This finding has a crosscutting aspect in the area of human performance in that the licensee did not provide personnel with adequate resources for tracking abnormal, off-normal or alarm conditions. Specifically, Procedure 2.3.1 required daily checks of failed or continuously alarming annunciators but did not specify a method to perform these checks. (Section 4OA2)

Cornerstone: Barrier Integrity

- Green. The NRC identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, regarding the failure to promptly identify a significant condition adverse to quality regarding operation of the reactor above the licensed thermal power limits for 3 days. On June 20, 2006, licensee personnel inadvertently introduced a nonconservative error into the core thermal power calculation which was not discovered until June 23. As a result, the reactor was operated above the licensed thermal power limit of 2381 MW for 3 days. Reactor power remained below 102 percent during the entire period; therefore, the reactor was not operated outside its design limits. This issue was entered into the licensee's corrective action program as Condition Report CR-CNS-2006-04573.

The finding is more than minor because it is associated with the Barrier Integrity cornerstone attribute of human performance (procedure adherence) and affects the associated cornerstone objective to provide a reasonable assurance that physical design barriers, such as fuel cladding, protect the public from radionuclide releases caused by accidents or events. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only involved the potential to affect the fuel barrier. 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 identify this issue in a timely manner. (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 correction action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The plant began the inspection period at 100 percent reactor power. The licensee entered and subsequently exited a Notice of Unusual Event (NOUE) on July 25, 2006, based upon the report of smoke in the service water pump room. On September 15, 2006, reactor power was reduced to 70 percent to facilitate repairs to a condensate booster pump. Full power operation resumed on September 19 and continued throughout the remainder of the inspection period.

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

1R04 Equipment Alignment (71111.04)

.1 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.

- August 9, 2006, south scram discharge instrument volume
- September 6, 2006, High Pressure Coolant Injection (HPCI) while Reactor Core Isolation Cooling (RCIC) was inoperable for preventative maintenance
- September 19, 2006, RCIC while HPCI was inoperable for preventative maintenance

Documents reviewed by the inspectors included:

- System Operating Procedure 2.2.8B, “Control Rod Drive Hydraulic System Instrument Valve Checklist,” Revision 1
- Work Order 4495159

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the UFSAR, Technical Specifications (TS), and vendor manuals to determine the correct alignment of the emergency diesel generators (EDG); (2) reviewed outstanding design issues, operator workarounds, and UFSAR documents to determine if open issues affected the functionality of the EDG system; and (3) verified that the licensee was identifying and resolving equipment alignment problems. Documents reviewed by the inspectors are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors walked down the seven plant areas listed below to assess the material condition of active and passive fire protection features and their operational alignment. 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 CAP to determine if the licensee identified and corrected fire protection problems.

- July 25, 2006, Fire Zone 8E, Battery Room 1A
- July 25, 2006, Fire Zone 8H, DC Switchgear (SWGR) Room 1A
- August 1, 2006, Fire Zone 8A, Auxiliary Relay Room
- August 1, 2006, Fire Zone 8B, Reactor Protection System (RPS) Room 1B
- August 1, 2006, Fire Zone 8C, RPS Room 1A
- August 1, 2006, Fire Zone 8F, Battery Room 1B

- August 1, 2006, Fire Zone 8G, DC SWGR Room 1B

Documents reviewed by the inspectors included:

- CNS Fire Hazards Analysis Report, June 20, 2002

The inspectors completed seven samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

Semi-Annual Internal Flooding

a. Inspection Scope

The inspectors reviewed the UFSAR, the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding from the main condenser and its associated cooling water supply. The inspection included a review of the UFSAR and CAP to determine if the licensee identified and corrected flooding problems. The inspectors also conducted a walkdown of the 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, (3) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

Quarterly Inspection

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators in the simulator on one occasion to verify adequacy of the training, to assess operator performance, and to assess the evaluator's critique. The inspectors observed a simulator scenario involving an anticipated transient without scram and an unisolable steam leak. Documents reviewed by the inspectors included:

- Lesson Plan SKL052-52-78, Crew C Annual Simulator Evaluation, dated August 1, 2006

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

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.

- August 22, 2006, Condition Report CR-CNS-2004-7473, maintenance rule evaluation of replacement of the EDG engine drive lube oil pump discharge hoses with flexible metal hoses

The inspectors completed one sample.

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 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.

- July 31, 2006, service water intake bay manual cleaning

- August 16, 2006, maintenance on the 250 VDC Battery Charger B

- August 21, 2006, modifications to the 345KV St. Joseph transmission line

- August 22, 2006, Reactor Equipment Cooling (REC) Pump C preventive maintenance

Documents reviewed by the inspectors included:

- Work Orders 4517189, 4484478, 4456078, 4420928, 4457906

The inspectors completed four samples.

b. Findings

Introduction. The inspectors identified a Green noncited violation (NCV) regarding the online risk evaluation for a surveillance test on safety-related undervoltage relays.

Description. On August 21, 2006, the licensee performed Surveillance Procedure 6.2EE.302, “4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2),” Revision 13. Bus 1G is one of two safety-related busses and is rendered inoperable during this surveillance test since it will not transfer to its backup power supply (the Emergency Station Service Transformer [ESST]) or to its standby power supply (EDG 2) during the test. This surveillance test was the only significant input to the online risk assessment tool for August 21 which resulted in a Yellow risk condition (Core Damage Frequency [CDF] greater than 1.3×10^{-5} but less than 5.99×10^{-5}). No specific risk management actions were required by the licensee’s procedures due to the short duration of the test (typically less than 2 hours).

Coincident with this surveillance test, the inspectors observed a line crew working on a 345 KV transmission tower in the owner controlled area (OCA). The transmission tower supported the St. Joseph 345 KV line as it passes over a 69 KV and 161 KV line. These two lower voltage lines are connected to the ESST and Station Startup Service Transformer (SSST), respectively. The ESST and the SSST are the safety-related offsite power sources required to be operable by TSs. The inspectors questioned both the control room operators and the work control organization as to the nature of the transmission work; plant personnel were aware that work was to be performed on the St. Joseph 345 KV transmission line but they were unaware of the exact location and nature of the work since this line is not owned by Nebraska Public Power District and the work was to be performed by an outside line crew.

Upon further investigation, the inspectors learned that the work on the 345 KV transmission line was to modify a number of wooden transmission towers in the OCA to increase their height, thereby increasing the capacity of the line since its current capacity was limited by line sag. The modification entailed placing steel braces on either side of the transmission structures and cutting the poles with a chainsaw. Then a hydraulic jack was to be used to raise the poles so they could be secured at the increased height by bolting them to the steel braces. The line crew had completed the work on the transmission structures inside the OCA without incident before the licensee or the inspectors arrived at a full understanding of the work scope.

The inspectors concluded that the modification work on the transmission structures increased the likelihood of a loss of offsite power (LOOP) due to the location of the structures being modified. Had one of the towers fallen while it was being cut with the chainsaw, it would have resulted in a fault on the St. Joseph 345 KV line as well as the 69 KV and 161 KV lines. In addition to losing 1 of 5 redundant 345 KV sources to the switchyard, this fault would have caused a loss of the ESST and challenged operability of the SSST. Bus 1G was already inoperable at the time due to testing and would not have transferred to EDG 2, leaving only Bus 1F available to supply power to the safety-related loads.

Regulatory Guide (RG) 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,” dated May, 2002, provides guidance on methods acceptable to the NRC staff for assessing and managing the increase in risk that may result from maintenance activities. RG 1.182 endorses the use of the Nuclear Energy Institute’s guidance contained in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities," dated February 22, 2000. This guidance states that when assessing the risk resulting from the performance of maintenance activities, the assessment may be quantitative or qualitative, and should consider the likelihood of an initiating event that would require the performance of the affected safety function. Contrary to this, the risk assessment associated with surveillance testing on Bus 1G did not consider the increase in the likelihood of a LOOP due to the transmission tower modifications. Furthermore, the licensee’s procedures for assessing risk did not explicitly require external factors, such as transmission system work or switchyard maintenance, to be considered when assessing the risk of maintenance on safety-related busses or the EDGs.

The licensee documented this issue in Condition Report CR-CNS-2006-06099.

<u>Analysis</u>. The performance deficiency associated with this finding involved the licensee’s failure to adequately assess the risk associated with surveillance testing of Bus 1G in accordance with the guidance in NUMARC 93-01, Section 11. The finding affected the Initiating Events Cornerstone and is more than minor because the licensee’s risk assessment failed to consider unusual external conditions that were present during the surveillance test (e.g, transmission system modifications that involved cutting transmission towers in the vicinity of transmission lines important to safety). The inspectors determined that a qualitative risk assessment should have been performed. Manual Chapter 0609, Appendix K, “Maintenance Risk Assessment and Risk Management Significance Determination Process,” does not apply to qualitative risk analyses; therefore, the finding is not suitable for SDP evaluation. However, the finding has been reviewed by NRC management and is determined to be a finding of very low safety significance. This determination took into consideration the short duration of the work and the fact that the surveillance procedure and the transmission work were both completed without any adverse consequences.

The cause of the finding is related to the crosscutting element of human performance in that the licensee’s work control process did not appropriately incorporate risk insights regarding the transmission system work while planning Bus 1G undervoltage testing.

Enforcement. Title 10 of the Code of Federal Regulations, Section 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," requires that before performing maintenance activities, including surveillance tests, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, on August 21, 2006, the licensee failed to adequately assess the increase in risk associated with the performance of Surveillance Procedure 6.2EE.302, "4160V Bus 1G Undervoltage Relay and Relay Timer Functional Test (Div 2)," Revision 13. Specifically, the licensee's risk assessment for August 21 failed to consider the increase in the likelihood of a loss of offsite power due to a modification to the transmission system inside the OCA. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as CR-CNS-2006-06099, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2006004-01, Inadequate Risk Assessment for Safety-Related Undervoltage Relay Testing.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

For the following six equipment performance issues, the inspectors: (1) reviewed plant status documents such as 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 SDP 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.

- July 17, 2006, high out-of-specifications air flow through the control room emergency filtration system (CREFS) charcoal beds
- July 27, 2006, HPCI lube oil contamination
- July 27, 2006, EDG relays not rated for application
- July 29, 2006, service water intake bay silt levels
- August 9, 2006, suppression chamber inlet isolation valve, PC-AOV-237AV, seismic calculation error
- September 19, 2006, scaffolding interference with REC system

The inspectors completed six samples.

b. Findings

Introduction. The inspectors identified a Green NCV of TS 5.4.1.a regarding the licensee's failure to follow procedures for maintenance affecting the performance of safety-related equipment.

Description. While conducting routine plant status walkdowns, the inspectors identified a violation of Maintenance Procedure 7.0.7, "Scaffolding Construction and Control," Revision 20, with three examples. Step 6.4.1 of Maintenance Procedure 7.0.7 provides a table of minimum separation distances to operable safety-related equipment during scaffolding construction. Contrary to the requirements of this table, the inspectors identified three occurrences where scaffolding was built in contact with operable safety-related systems.

On June 8, 2006, inspectors identified that scaffolding poles and planks were installed in contact with the Division 1 Residual Heat Removal (RHR) piping. The scaffolding was installed under Work Order 4478526 to facilitate the installation of hydrolazing taps in the RHR piping. Procedure 7.0.7 directs that the separation distance to operable safety-related piping shall be "not touching." The inspectors discovered that one scaffolding pole was built in contact with the insulation on the RHR heat exchanger relief line. In addition, one set of scaffolding planks was built in contact with the heat exchanger discharge piping such that it compressed the metallic insulation package approximately ½ inch. The licensee documented this discrepancy in CR-CNS-2006-04251. After further discussions with the inspectors on August 7, 2006, Procedure 7.0.7 was revised to more clearly prohibit scaffolding contact with the insulation on safety-related piping.

Secondly, on September 14, 2006, inspectors identified scaffolding in contact with the baseplate of Pressure Switch SW-PS-364A which provides the low pressure isolation signal to Valve SW-MOV-37 in the event of a pipe break in the service water system. This scaffold was installed to facilitate service water piping inspections under Work Order 4512021. Procedure 7.0.7 requires that scaffolding be greater than one inch away from this component. As a result of the inspector's observation, the scaffolding was reconfigured.

Lastly, on September 19, 2006, the inspectors discovered scaffolding built per Work Orders 4512022 and 4512028 in contact with the Valve REC-V-712, the Division 1 REC heat exchanger discharge valve. According to Procedure 7.0.7, the minimum separation distance for this component is "not touching." The licensee documented this discrepancy in CR-CNS-2006-06763.

The inspectors noted that Procedure 7.0.7 allows scaffolds to be built within the minimum separation distance of step 6.4.1 if a Scaffold Engineering Evaluation (SEE) is performed. The inspectors verified that none of these three examples received an SEE prior to being identified as discrepant. Operability determinations performed after the identification of each violation demonstrated that operability of the affected safety system was not adversely affected. The inspectors concluded that these examples demonstrated a programmatic weakness in that scaffold construction was not being routinely built or inspected to the standards of Procedure 7.0.7.

The inspectors also noted that upon completion, each scaffolding requires only one supervisory review prior to being accepted for unrestricted use. Step 4.13 of Procedure 7.0.7 requires post-construction scaffolding examinations to be performed by the "utility or construction supervision or designee that have successfully completed scaffold training." Contrary to this requirement, the contract supervisor who performed the post-construction examination of the scaffold built for Work Order 4512022 had received no formal training on the requirements of Procedure 7.0.7. After discussion with the inspectors the licensee documented this discrepancy in CR-CNS-2006-06973.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to properly control the installation of scaffolding near operable safety-related equipment as required by plant procedures. The finding affected the Mitigating Systems Cornerstone and is more than minor because, if left uncorrected, the failure to maintain the standards of Procedure 7.0.7 could become a more significant safety concern. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding was 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.

This finding has a cross-cutting aspect in the area of human performance in that the licensee did not effectively communicate expectations regarding work practices and compliance with Procedure 7.0.7 to workers constructing scaffolding or to supervisors who routinely monitor these activities.

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in RG 1.33, Revision 2, Appendix A, dated February 1978. RG 1.33, Appendix A, Section 9 (a), requires that maintenance that can affect the performance of safety-related equipment should be performed in accordance with written procedures. Maintenance Procedure 7.0.7, "Scaffolding Construction and Control," Revision 20, provides minimum separation distances when building scaffolding near operable safety-related equipment. Contrary to this procedural requirement, scaffolding was built without satisfying the minimum separation distance on three occasions. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-06763, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006004-02, "Failure to Follow Requirements for Scaffolding Construction."

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected six 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 post-maintenance testing.

- August 2, 2006, Core Spray Injection Valve CS-MOV-MO12A auxiliary contactor replacement
- August 17, 2006, 250 VDC Battery Charger B output breaker replacement
- August 22, 2006, REC Pump C auxiliary contact and fuse block replacement
- August 31, 2006, Control Rod Drive Pump B replacement
- September 20, 2006, HPCI in-service test following routine maintenance
- September 21, 2006, secondary containment penetration examination following removal of a temporary modification which utilized the penetrations

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

- July 19, 2006, CREFS air flow testing

- August 2, 2006, Core Spray Injection Valve CS-MOV-MO12A quarterly valve strokes

- August 17, 2006, 250 VDC Battery Charger B load test

- August 18, 2006, Reactor Coolant System (RCS) leak rate determination

- August 23, 2006, REC System D in service test

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2006 biennial emergency plan exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario simulated an offsite earthquake, reactor power in the stability exclusion region, the loss of a vital electrical bus and station air compressors, a reactor coolant leak inside containment, the loss of reactor heat removal capability, core damage, very high pressure in containment, and a planned radiological release to the environment via the hardened vent to protect containment, to demonstrate the licensee's capabilities to implement the emergency plan.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of event classification, offsite notification, recognition of offsite dose consequences, and development of protective action recommendations, in the simulator control room and the following dedicated emergency response facilities:

- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed recognition of and response to abnormal and emergency plant conditions, the transfer of decision making authority and emergency function responsibilities between facilities, onsite and offsite communications, protection of emergency workers, emergency repair evaluation and capability, and the overall implementation of the emergency plan to protect public health and safety and the environment. The inspectors reviewed the current revision of the facility emergency plan, and emergency plan implementing procedures associated with operation of the above facilities and performance of the associated emergency functions. These procedures are listed in the Attachment to this report.

The inspectors compared the observed exercise performance with the requirements in the facility emergency plan, 10 CFR 50.47(b), 10 CFR Part 50, Appendix E, and with the guidance in the emergency plan implementing procedures and other federal guidance.

The inspectors attended the post-exercise critiques in the simulator control room and emergency operations facility to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended a subsequent formal presentation of critique items to plant management.

The inspectors completed one sample during the inspection.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspector performed an in-office and on-site review of Revision 51 to the Cooper Nuclear Station Emergency Plan, implemented June 16, 2006. This revision implemented the offsite Auburn Emergency Response Facility, deleted the Auburn Alternate Emergency Response Facility, updated references to the Department of Homeland Security National Response Plan, added Richardson County to descriptions of communications capabilities, added a description of methods to call out joint information center personnel when required, and corrected the described location of an offsite hospital used to treat contaminated and injured personnel.

The revision was compared to the previous revision, 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 the standards of NUREG-0696, "Functional Criteria for Emergency Response Facilities," to the standards of NUREG-0737, "Clarification of TMI Action Plan Requirements," Supplement 1, to the criteria of NUREG-0814, "Methodology for the Evaluation of Emergency Response Facilities," and to the standards in 10 CFR 50.47(b) to determine if the revision(s) was (were) adequately conducted following the requirements of 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 revisions are subject to future inspection.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed an unannounced emergency preparedness drill conducted on August 22, 2006. The observations were made in the Technical Support Center and concentrated on 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 failures. Documents reviewed by the inspectors included:

- ERO Team 2 Drill Scenario dated August 22, 2006

The inspectors completed one sample

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

Mitigating Systems

The inspectors sampled licensee submittals for the performance indicators listed below for the period July 2004 through July 2006. The definitions and guidance of Nuclear Energy Institute 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 performance indicator data reported during the assessment period. Licensee performance indicator data were also reviewed against the requirements of Procedure 0-P1-01, A “Performance Indicator Program,” Revision 16.

- Safety System Function Failures

Emergency Preparedness

The inspectors reviewed licensee evaluations for the three emergency preparedness cornerstone performance indicators of Drill and Exercise Performance, Emergency Response Organization Participation, and Alert and Notification System Reliability, for the period April 1, 2005, through June 30, 2006. The definitions and guidance of Nuclear Energy Institute 99-02, "Regulatory Assessment Indicator Guideline," Revisions 2 and 3, and the licensee Performance Indicator Procedures 0-PI-01, "Performance Indicator Program," Revision 19, and Emergency Preparedness Desk Guide 2, Attachment G-1, "Emergency Preparedness Cornerstone Performance

Indicator Data Collection Guide," Revision 12, were used to verify the accuracy of the licensee’s evaluations for each performance indicator reported during the assessment period.

The inspectors reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspectors reviewed 42 selected emergency responder qualification, training, and drill participation records. The inspectors reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspector also reviewed other documents listed in the Attachment to this report.

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

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.

.2 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-2006-05303, NOUE Declaration
- Cumulative Review of Operator Work Arounds

The inspectors completed two samples.

b. Findings

Introduction: The inspectors identified a Green NCV of TS 5.4.1.a regarding the licensee’s inadequate procedure for tracking abnormal, off-normal or alarm conditions.

Description: On August 11, 2006, during the annual review of operator work arounds, the inspectors identified that a failed control room annunciator was not being controlled as required by Alarm Procedure 2.3.1, “General Alarm Procedure,” Revision 51.

On June 11, 2006, the generator defoaming tank high level annunciator was received in the control room. Operators responded in accordance with the alarm procedure and determined that no actual alarm condition existed. As a result, the operators believed that annunciator had failed and it was marked with a self-adhesive green flag in accordance with Procedure 2.3.1. When the alarm reset later on the same day the tag was not removed, contrary to the guidance of of Procedure 2.3.1, step 8.10.1, which states, “when annunciator/related component is repaired or conditions change to stop continuous annunciation...ensure green self-adhesive flag removed from affected annunciator window.” This discrepancy was identified by the inspectors during a review of control room deficiencies on August 11, 2006. The licensee documented the procedural violation in Condition Report CR-CNS-2006-05852 on August 14, 2006.

The inspectors reviewed the licensee’s process for monitoring failed annunciators. Procedure 2.3.1; step 8.11.a, requires operators to “once/day, review failed or continuously alarming annunciators.” The inspectors noted that a daily review of disabled annunciators is required and is conducted by the operators, but that not all failed annunciators are disabled in the system. Because it was not disabled, the improper flagging of the generator defoaming tank high level annunciator was not discovered by the operators for two months after it had cleared. The inspector discovered several other examples of failed annunciators that were not being checked daily due to the fact that they were not disabled. This failure to perform daily reviews of failed annunciators represented a missed opportunity remove the green self-adhesive flag. The licensee documented this procedural discrepancy as CR-CNS-2006-06652 on September 15, 2006.

Analysis: The performance deficiency associated with this finding involved the licensee’s failure to provide adequate procedures for performing daily checks of control room-annunciators. The finding is greater 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 (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.

This finding has a crosscutting aspect in the area of human performance in that the completeness and accuracy of the resources for tracking abnormal, off-normal or alarm conditions were not maintained. Specifically, Procedure 2.3.1 required daily checks of failed or continuously alarming annunciators but no method was specified to perform these checks.

Enforcement: TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in RG 1.33, Revision 2, Appendix A, dated February 1978. RG 1.33, Appendix A, Section 5, requires procedures for alarm conditions. Contrary to this requirement, the guidance in Alarm Procedure 2.3.1, "General Alarm Procedure," Revision 51, was inadequate in that it did not provide sufficient guidance to allow operators to perform a daily check of failed or continuously alarming annunciators. As a result, from June 11, 2006, to August 11, 2006, operators failed to identify that the generator defoaming tank high level annunciator was incorrectly labelled as being failed. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2006-05852, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000528/2006004-03, "Inadequate Procedure for Tracking Failed Control Room Annunciators."

.3 Emergency Preparedness Annual Sample

a. Inspection Scope

The inspectors reviewed a summary list of corrective actions initiated between September 2004 and July 2006, and reviewed nine licensee drill and exercise evaluation reports, as listed in the Attachment, to identify previous emergency response organization weaknesses and deficiencies. The inspectors compared licensee performance during the biennial exercise with previous performance to identify trends and to evaluate the effectiveness of previous corrective actions.

b. Findings

No finding of significance were identified.

4OA3 Event Follow-up (71153)

.1 Event Response

The inspectors responded to the control room on July 25, 2006, and observed operator response to a fire detection system actuation in the service water pump room which resulted in the declaration of an NOUE. The inspectors verified that operator actions were in accordance with plant procedures and the emergency plan and that the licensee had identified and implemented appropriate corrective actions associated with personnel performance problems that occurred during the event.

.2 (Closed) Licensee Event Report 05000298/2006-003: Both Diesel Generators Inoperable Due to Voltage Regulator Design Results in Loss of Safety Function

On April 21, 2006, the licensee discovered that a 1998 modification to the voltage regulators on EDG 1 and EDG 2 had never been completed and, as a result, the current procedures for performing monthly EDG surveillance tests did not accurately reflect the system operating characteristics. The intent of the modification was to allow the EDG voltage regulators to automatically shift into isochronous mode if offsite power were lost during the monthly surveillance test, thereby maintaining operability of the EDGs during testing. This portion of the modification was never completed; however, the requirement to declare an EDG inoperable during testing was removed from the test procedures. As a result, between 1998 and April 2006 the EDGs were actually inoperable during surveillance testing but were never declared inoperable by the licensee. The licensee reviewed their test records and determined that this condition resulted in both EDGs being rendered inoperable at the same time on March 23, 2004. The licensee documented this issued in Condition Report CR-CNS-2006-03093 and implemented actions to correct the erroneous surveillance procedures. The enforcement aspects of this issue are discussed in Section 4OA7. This item is closed.

4OA5 Other Activities

.1 Reactor Operation in Excess of Licensed Thermal Power Limits

a. Inspection Scope

The inspectors reviewed a licensee identified violation of their licensed thermal power limit. This review included interviews of personnel involved with the investigation as well as a review of plant procedures, control room logs, and plant computer data to determine if the licensee fully understood the causes of this violation.

b. Findings

Introduction: The inspectors identified a Green noncited violation regarding the failure to promptly identify a significant condition adverse to quality regarding operation of the reactor above the licensed thermal power limits for 3 days.

Details: On June 23, 2006, control room operators discovered that a non-conservative value for the Reactor Water Cleanup System (RWCU) flow rate had been substituted into the plant computer's core thermal power calculation which resulted in an indicated core power that was approximately 2 MW (thermal) less than actual core power. Since indicated reactor power was essentially at 100 percent, operators determined that the reactor was actually operating at approximately 2383 MW which exceeded the licensed thermal power limit of 2381 MW. As a result, operators immediately reduced reactor power and corrected the value for RWCU system flow rate in the plant computer. Upon further review, the licensee determined that this error had been introduced approximately 3 days earlier on June 20 and, while the reactor had been operating in excess of licensee thermal power during those 3 days, no core thermal limits had been exceeded.

The RWCU system is equipped with two filters that contain resins which remove impurities from the reactor coolant. In order to prevent damage to the filters and resins, the reactor coolant passes through three regenerative heat exchangers and two non-regenerative heat exchangers to lower its temperature before passing through the filters. Since this system effectively removes a small amount of heat from the reactor core, the plant computer uses flow rate through the system as a parameter in the core thermal power calculation to account for this heat loss. The system flow rate is monitored by flow elements associated with each filter. When a filter is bypassed for routine maintenance, the flow element is also bypassed so indicated system flow decreases even though actual system flow remains the same. Since the system continues to remove the same amount of heat from the reactor core when a filter is bypassed, the value for flow rate through the RWCU system has to be manually substituted into the core thermal power calculation to ensure that it remains accurate.

The licensee documented this reactivity management error in Condition Report CR-CNS-2006-04573 and performed an apparent cause determination. Their evaluation was completed on July 25, 2006, and determined that RWCU Filter A had been bypassed for routine maintenance in the early morning hours of June 20, 2006. During this two hour evolution, both Filters A and B were bypassed at various times as the system was realigned to support the maintenance. The flow values through both filters had been appropriately substituted into the core thermal power calculation in accordance with System Operating Procedure 2.6.3, “Computer System Operation and Outage Recovery,” Revision 19. However, upon completion of the maintenance and restoration of normal flow through both filters, the value for flow through Filter B was not returned to normal even though there had been an apparent attempt to do so as indicated by an entry in the control room logs. Therefore, an artificially high value for RWCU system flow was used for the thermal power calculation which resulted in indicated core power being approximately 2 MW less than actual core power. The licensee stated that the apparent cause of this condition was that self-checking techniques had not been used by the operator when restoring the system flow values to normal. The licensee also stated that the requirement to substitute the flow values was contained in the operating procedure for the plant computer, not the procedure for the RWCU filters which drove the operator to perform these steps from memory. There were no corrective actions assigned in the CAP to address either of the stated causes.

The inspectors performed an independent determination of the causes for this error and concluded that the licensee’s evaluation was correct but it had not been thorough in identifying all of the performance issues or in the assignment of corrective actions. The inspectors reviewed the control room logs and plant computer data for June 20 as well as the associated procedure requirements. The inspectors found that the licensee had missed an opportunity to identify this condition 8 hours after it occurred rather than 3 days later. Conduct of Operations Procedure 2.0.2, “Operations Logs and Reports,” Revision 80, required operators to generate a daily report of plant computer values that were “unhealthy.” This report included all computer variables that had been manually substituted in the previous 24 hours. The procedure also required a condition report and corrective actions for any unexpected values on the report. The report generated on the morning of June 20 indicated that the value for flow through Filter B was substituted with an artificially high value. The control room failed to identify the condition based on this report and took no corrective actions. This aspect of the error was not mentioned in the licensee's apparent cause evaluation.

After the inspectors brought these performance issues to the licensee's attention, the apparent cause determination was re-opened to investigate the issues in more detail.

Analysis: The performance deficiency associated with this finding involved the failure to promptly identify reactor core operation above the licensed thermal power limit. Operation above the licensed power limit is considered to be a significant condition adverse to quality and it was reasonably within the licensee's ability to have identified it earlier than 3 days based on a daily plant computer report. The finding is more than minor because it is associated with the Barrier Integrity cornerstone attribute of human performance (procedure adherence) and it affects the associated cornerstone objective to provide reasonable assurance that physical design barriers, such as fuel cladding protect the public from radionuclide releases caused by accidents or events. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because it only involved the potential to affect the fuel barrier.

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 identify this issue in a timely manner.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformance are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management. Contrary to this, an error introduced into the core thermal power calculation on June 20, 2006, was not identified until June 23, 2006, despite a computer report generated on June 20 that indicated the error. Operators reviewed this report but failed to identify the error and correct it. As a result, the reactor was operated above the licensed thermal power limit of 2381 MW for 3 days. Because this violation was of very low safety significance and was entered in the CAP as CR-CNS-2006-04573, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000298/2006004-04, "Failure to Promptly Identify Reactor Operation in Excess of Licensed Thermal Power Limits."

.2 (Closed) Unresolved Item 05000298/2005015-02: Potential for Plugging of REC Heat Exchangers During a Design Basis Accident.

The inspectors completed a follow-up inspection for an unresolved item regarding the potential for plugging of the REC heat exchangers during a design basis accident. This item was left unresolved pending an analysis by the licensee of the effects of sedimentation that would result from the postaccident low-flow conditions in the REC heat exchangers. The inspectors reviewed the results of Design Calculation 94-021 Revision 4C1 and determined that the analysis was bounding and demonstrated that the potential sedimentation does not threaten the safety function of the REC heat exchangers.

To further validate this result, the inspectors performed a qualitative review of actual heat exchanger performance. The inspectors noted that the normal service water flow velocity in the turbine equipment cooling water (TEC) heat exchangers is similar to the post-accident flow velocity in the REC heat exchangers. Based on a review of TEC heat exchanger inspection results for the past four years, the inspectors determined that Design Calculation 94-021 overestimates the amount of sediment that would accumulate in the REC heat exchangers during a design basis accident.

Based on these results, the inspectors identified no performance deficiencies or violations of NRC requirements existed. No findings of significance were identified.

.3 (Closed) Unresolved Item 05000298/2005008-07: No Analysis to Demonstrate that the DG Building Ventilation System can Withstand the Depressurization Effects of a Tornado.

The issues associated with the licensee's tornado protection design were documented in NRC Inspection Report 05000298/2005008 and included unresolved questions regarding Cooper Nuclear Station's licensing basis requirements for tornado protection as well as the potential consequences of a tornado strike on the EDG Building. As a result, the licensee performed an analysis of the EDG Building ventilation system which demonstrated that it would remain functional during a design basis tornado event. The NRC staff reviewed this analysis as well as the licensing basis requirements and concluded that the licensee's analysis was acceptable, and that the ventilation system would most likely remain functional if the building were impacted by a tornado. Furthermore, the staff concluded that the licensing basis for Cooper Nuclear Station did not require this analysis to be performed. Therefore, no violation of NRC requirements was identified. This item is closed.

4OA6 Meetings, Including Exit

On July 28, 2006, the inspectors conducted a telephonic exit meeting to present the results of the emergency preparedness inspection to Mr. S. Minahan, General Manager of Plant Operations, and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On October 5, 2006, the resident inspectors presented the results of their inspection activities to Mr. S. Minahan and other members of his staff who acknowledged the findings. The inspector confirmed that the supporting details in this report contained no proprietary information.

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 met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as Non-Cited Violations.

- Appendix B of 10 CFR Part 50, Criterion V, “Instructions, Procedures, and Drawings,” requires that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to this requirement, Surveillance Procedure 6.1DG.101, “Diesel Generator 31 Day Operability Test (IST) (DIV 1),” Revision 40, and Surveillance Procedure 6.2DG.101, “Diesel Generator 31 Day Operability Test (IST) (DIV 2),” Revision 42 were not appropriate to the circumstances in that they did not require EDG 1 or EDG 2 to be declared inoperable when paralleled to the grid during surveillance testing. As a result, both EDGs were rendered inoperable at the same time on March 23, 2004. 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 involved an actual loss of safety function. 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 condition existed an average of 159.8 hours annually (average total time the EDGs were paralleled to the grid annually). Additionally, the inspectors treated the EDGs as a single-train system since the performance deficiency only rendered one EDG inoperable at a time. No credit for recovery of a failed train was given due to the lack of procedures and training required to do so. Based on the results of the Phase 2 analysis, the finding is determined to have very low safety significance. This issue was identified in the licensee’s CAP as CR-CNS-2006-03093.

- License Condition 2.C(1) of the Cooper Nuclear Station Operating License states that the licensee is authorized to operate the facility at steady state reactor core power levels not in excess of 2381 MW (thermal). Contrary to this, from June 20-23, 2006, the reactor was operated between 2381 and 2383 MW due to an operator induced error in the core thermal power calculation. This finding had the potential to affect only the fuel cladding; however, no core thermal limits were exceeded. The licensee entered this condition in the CAP as CR-CNS-2006-04573.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

T. Bahensky, System Engineer
K. Chambliss, Operations Manager
J. Dykstra, Electrical Engineering Program Supervisor
R. Edington, Chief Nuclear Officer
R. Estrada, Corrective Actions Manager
J. Flaherty, Licensing
J. Florence, Simulator Supervisor
J. Gren, System Engineer
G. Hadley, System Engineer
T. Huff, Maintenance Rule Coordinator
G. Kline, Director, Engineering
J. Larson, Supervisor, Quality Assurance
M. McCormack, Electrical Systems/I&C Engineering Supervisor
E. McCutchen, Senior Licensing Engineer
M. Metzger, System Engineer
S. Minahan, General Manager of Plant Operations
A. Mitchell, Manager, Design Engineering
J. Roberts, Director, Nuclear Safety and Assurance
A. Sarver, Balance of Plant Engineering Supervisor
T. Shudak, Fire Protection Program Engineer
T. Stevens, Supervisor, Mechanical Engineering
D. Van Der Kamp, Acting Manager, Licensing
J. Waid, Training Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2006004-01	NCV	Inadequate Risk Assessment for Safety-Related Undervoltage Relay Testing.
05000528/2006004-02	NCV	Failure to Follow Requirements for Scaffolding Construction
05000528/2006004-03	NCV	Inadequate Procedure for Tracking Failed Control Room Annunciators
05000298/2006004-04	NCV	Failure to Promptly Identify Reactor Operation in Excess of Licensed Thermal Power Limits

Closed

05000298/2005015-02	URI	Potential for Plugging of REC Heat Exchangers During a Design Basis Accident
05000298/2005008-07	URI	No Analysis to Demonstrate that the DG Building Ventilation System can Withstand the Depressurization Effects of a Tornado
05000298/2006-003	LER	Both Diesel Generators Inoperable Due to Voltage Regulator Design Results in Loss of Safety Function

LIST OF DOCUMENTS REVIEWED

Section 1R12

Training System Manual for Emergency Diesel Generators
Design Criteria Documents, DCD-1, “Diesel Generators,” dated October 10, 2005
Maintenance Rule Expert Panel Meeting Minutes for August 22, 2006

Drawings:

NUMBER	TITLE/SUBJECT	REVISION
KSV-47-8	Diesel Generator 1 & 2 Cooling Water Schematic	N22
KSV-47-9-NP	Jacket Water Schematic Dated October 29, 1993	
KSV-48-5	Starting Air Schematic CIC’s	N5
KSV-51-8	Fuel Oil Piping Schematic	N8

Condition Reports:

CR-CNS-2004-07473	CR-CNS-2006-06203	CR-CNS-2006-06205
CR-CNS-2006-06206	CR-CNS-2006-06212	CR-CNS-2006-06213
CR-CNS-2006-06216		

Work Orders:

4503746	4505562	4504920
4507390		

Section 1R15

Maintenance Procedure 7.0.7, "Scaffolding Construction and Control," Revision 20 and Revision 21
Work Orders:

4478526	4512028	4512022
4512021	4512025	

Condition Reports:

CR-CNS-2006-04904	CR-CNS-2006-05120	CR-CNS-2006-05357
CR-CNS-2006-05671	CR-CNS-2006-05418	CR-CNS-2006-04251
CR-CNS-2006-06763		

Section 1R19

Procedures:

NUMBER	TITLE/SUBJECT	REVISION
7.3.28.1	EQ., Essential Maintenance Rule Risk Significant (MRRS) and Fire Protection Components Lead Removal/Installation and Lug Installation	17
6.1CS203	CS-MO-12A Operability Test With Reactor Pressure Less than 450 PS15 (IST) (DIV1)	0
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Condition Reports:

CR-CNS-2006-04284	CR-CNS-2006-06652	CR-CNS-2006-04815
CR-CNS-2006-05852	CR-CNS-2006-05303	

Drill Evaluation Reports:

Drill conducted October 13, 2004
Drill conducted December 9, 2004
Drill conducted March 9, 2005
2005 Dress Rehearsal Exercise
2005 Exercise
Drill conducted October 13, 2005
Drill conducted November 2, 2005
Drill conducted March 22, 2006
2006 Dress Rehearsal Exercise

Work Order 4511149

Cooper Nuclear Station Emergency Plan, Revisions 50 and 51

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Calculation NEDC 94-021, “REC HX-A & REC HX-B Maximum Allowable Accident Case Fouling,” Revision 4C1 on June 21, 2006.

Performance Evaluation Procedure 13.15.1, “Reactor Equipment Cooling Heat Exchanger Performance Analysis,” Revision 24.

Work Orders:

4175770	4345717	4326693
4477078		

Condition Report CR-CNS-2006-00195 Reactor Operation in Excess of Licensed Thermal Power Limits

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
CAP	corrective action program
CDF	core damage frequency
CFR	Code of Federal Regulations
CREFS	control room emergency filtration system
EDG	emergency diesel generator
ERO	emergency response organization
ESST	emergency station service transformer
HPCI	high pressure coolant injection
LER	licensee event report
LOOP	loss of offsite power
NCV	noncited violation
NOUE	notice of unusual event
OCA	owner controlled area
PI	performance indicator
RCIC	reactor core isolation cooling
RCS	reactor coolant system
REC	reactor equipment cooling
RG	Regulatory Guide
RHR	residual heat removal
RPS	reactor protection system
RWCU	reactor water cleanup system
SDP	significance determination process
SEE	scaffold engineering evaluation
SSC	structure, system, and component
SSST	station startup service transformer
SWGR	switchgear
TEC	turbine equipment cooling
TSs	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item