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

February 13, 2006

EA-05-172

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 05000298/2005005

Dear Mr. Edington:

On December 31, 2005, 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 January 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, five 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:
NRC Inspection Report 05000298/2005005
w/attachments: Supplemental Information
Phase 3 Worksheets

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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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C:DRS/EB1	C:DRS/EB2	C:DRP/C		
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket.:	50-298
License:	DPR-46
Report:	05000298/2005005
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	September 24 through December 31, 2005
Inspectors:	S. Schwind, Senior Resident Inspector N. Taylor, Resident Inspector S. Cochrum, Resident Inspector P. Elkmann, Emergency Preparedness Inspector M. Haire, Operations Engineer
Approved By:	K. Kennedy, Branch C, Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000298/2005005; 09/24/05 - 12/31/05; Cooper Nuclear Station. Equipment Alignment, Event Followup, Other Activities.

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

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The NRC identified a noncited violation of 10 CFR Part 50, Appendix B, Criterion V, regarding the failure to implement procedure requirements for foreign material exclusion. The licensee failed to establish Zone 1 controls in accordance with Administrative Procedure 0.45, "Foreign Material Exclusion Program," during modification of the service water intake bay traveling water screens. This resulted in the introduction of foreign material into the intake bay which had the potential to adversely affect the service water system. This was entered into the licensee's corrective action program as Condition Report CR-CNS-2005-08930.

  The finding is greater than minor because if left uncorrected, the continued introduction of foreign material into the service water intake bay would become a more significant safety concern. The continued failure to implement this program could result in the loss of safety function of a safety-related system. The finding affected the Mitigating Systems cornerstone. Using the Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," the finding was determined to have very low safety significance because there was no loss of function for the service water (Section 1R04).

- Green. A self-revealing noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified regarding the failure to correct a degraded condition on the reactor equipment cooling system. A leaking manual isolation valve was identified in the corrective action program in July 2002, but the condition was never corrected and the corrective action documents were closed. In August 2005, this valve was relied upon to maintain system integrity during maintenance. The leaking valve resulted in the system being declared inoperable and required entry into Technical Specification 3.0.3. The licensee entered this into their corrective action program as Condition Report CR-CNS-2005-05588.

  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. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the licensee was able to demonstrate that there was no loss of safety function for any mitigating systems and the finding did not screen as risk significant due to external initiating events. The cause of the finding is related to the crosscutting element of problem identification and resolution in that a condition adverse to quality was not corrected in 2003 (Section 4OA2.2).

- Green. A self-revealing, noncited violation of Technical Specification 5.4.1.a was identified regarding implementation of the scram procedure during response to a manual reactor scram on September 23, 2005. During scram recovery actions, operators failed to minimize feedwater to the reactor which resulted in the only operating reactor feed pump tripping on high reactor vessel water level. The licensee entered this into their corrective action program as Condition Report CR-CNS-2005-06960.

  The finding is greater 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. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because there was no loss of safety function for the mitigating system and the finding did not screen as risk significant due to external initiating events. The cause of the finding is related to the crosscutting element of human performance in that it was reasonable to have expected the reactor operator to correctly prioritize the scram actions and prevent the loss of reactor feed (Section 4OA3.1).

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified regarding inadequate corrective actions for repetitive failures of a lube oil instrument line on Emergency Diesel Generator 1. Between 1989 and 2004, the configuration of this instrument was susceptible to high-cycle fatigue failures and experienced three such failures. Corrective actions only replaced the failed material; the line remained in a configuration susceptible to further failures. On December 30, 2004, the line catastrophically failed during a monthly surveillance test, resulting in 100-150 gallons of oil spraying into the room. The licensee entered this into their corrective action program as Condition Report CR-CNS-2004-07947.

  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. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because the inspectors determined that there was a loss of safety function of the single train for greater than the Technical Specification allowed outage time. 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 this finding is related to the crosscutting element of problem identification and resolution in that the licensee failed to take corrective actions to preclude repetitive failures of the lube oil instrument line (EA-05-172) (Section 4OA5.2).

- Green. A self-revealing, noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified regarding inadequate corrective actions for a repetitive failure of a safety-related 4160 volt breaker. In December 2000, a safety-related breaker failed to operate due to inadequate clearances between internal components. Corrective actions for this failure did not prevent an identical failure of the breaker for Service Water Pump A in December 2004. The licensee entered this into their corrective action program as Condition Report CR-CNS-2004-07938.

  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. In addition, the finding is also associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because two reactor safety cornerstones were affected. 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 a corrective action designed to prevent recurrence of the failure in 2004 was closed without being implemented (Section 4OA5.3).

REPORT DETAILS

Summary of Plant Status

The plant was in a forced outage at the beginning of this inspection period due to an air leak in the main condenser which necessitated a manual reactor scram. On September 25, 2005, the reactor was restarted and full power operation resumed on September 27. On December 2, reactor power was reduced to approximately 70 percent for corrective maintenance on main condenser tubes. Full power operation resumed on December 3. On December 9, reactor power was reduced to approximately 70 percent for corrective maintenance on main condenser tubes. Full power operation resumed on December 11. The reactor remained at essentially 100 percent power for the remainder of the period.

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

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors completed a review of the licensee's readiness of seasonal susceptibilities involving extreme low temperatures. The inspectors: (1) reviewed plant procedures, the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications (TSs) to ensure that operator actions defined in adverse weather procedures maintained the readiness of essential systems; (2) walked down portions of the two systems listed below to ensure that adverse weather protection features (heat tracing, space heaters, weather proof enclosures, temporary chillers, etc.) were sufficient to support operability, including the ability to perform safe shutdown functions; (3) evaluated operator staffing levels to ensure the licensee could maintain the readiness of essential systems required by plant procedures; and (4) reviewed the corrective action program (CAP) to determine if the licensee identified and corrected problems related to adverse weather conditions.

- November 30, 2005: Service Water Intake
- December 21, 2005: Division 1 and 2 250 Volt (V) Batteries

Documents reviewed by the inspectors included:

- General Operating Procedure 2.1.14, “Seasonal Weather Preparations,” Revision 1, dated May 3, 2004

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors: (1) walked down portions of the two 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 UFSAR and CAP to ensure problems were being identified and corrected.

- October 4, 2005 - Residual Heat Removal System, Loop A. The walkdown included portions of the system in the reactor building.

- November 20, 2005 - Service Water System. The walkdown included portions of the system in the intake structure.

The inspectors completed two samples.

b. Findings

Introduction. The inspectors identified a Green noncited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, regarding the licensee's failure to follow the requirements of the Foreign Material Exclusion (FME) Program during installation of a new traveling screen in the service water (SW) intake bay. This failure to implement the proper FME controls allowed the introduction of foreign material into the work area and made the required cleanliness inspection impossible to perform.

Description. On November 23, 2005, during a walkdown of the SW intake bay, the inspectors discovered a ratchet wrench that had been left in the bay during installation of the new traveling screen. In addition, the inspectors reviewed Condition Report CR-CNS-2005-08890 which documented that a pipe fitting had been dropped near the traveling screen work area and had bounced through an open hole into the SW intake bay on December 5, 2005. Based on these two issues, the inspectors reviewed the licensee's FME controls for the SW bay since both of these items had the potential to affect operability of the SW system.

On November 14, 2005, Zone 2 FME controls were established for the installation of a new traveling screen in the SW intake bay under Work Order 4431742. These FME requirements were established for both the opened sparger and screen wash piping and the general area around the screens due to the potential adverse effects of foreign material being introduced downstream of the traveling screens. Administrative Procedure 0.45, "Foreign Material Exclusion Program," Revision 21, establishes two distinct levels of FME controls: Zones 1 and 2. Zone 2 controls are appropriate in areas where retrieval of lost material is possible and cleanliness inspections can be performed. Zone 1 controls are more stringent and are intended for areas "where final inspection of area cleanliness or immediate retrieval of foreign material is not possible." Zone 1 controls would include such measures as accountability logs and FME zone monitoring.

The inspectors found that the procedural requirements for Zone 2 FME controls could not be implemented because a thorough inspection of the SW bay for foreign material could not be performed following completion of the work. This is because the poor water quality in the bay precludes any type of visual inspection and divers cannot be used to inspect the bay since there is a requirement to keep at least one SW pump running at all times. Therefore, Zone 1 FME requirements should have been implemented during this work activity. If correctly implemented, Zone 1 FME controls would have prevented the ratchet wrench from being left in the SW intake bay.

In addition, the inspectors determined that the Zone 2 FME controls were not adequately implemented. Administrative Procedure 0.45 requires that a quality control (QC) inspection shall be conducted for all systems and components controlled by this procedure. QC signatures were required on Administrative Procedure 0.45, Attachment 3, Section 3, “System Cleanliness Requirements,” and Section 4, “Final Inspection,” both of which were attached to the work order. Neither of these QC inspection signatures were obtained prior to placing the traveling screen in service on December 8, 2005. The inspection activity documented in Section 3 was a vacuuming operation conducted by contract divers under the work area, but the diver documented that some areas beneath the screens were not able to be vacuumed. The inspection activity documented in Section 4 was limited to two precloseout walkdowns conducted by persons not qualified to complete the QC cleanliness inspection. On December 14, 2005, a QC inspector added a note to each of these forms documenting that an FME inspection was not possible due to the sparger piping being closed up and unavailable for inspection. The QC inspector did not make any mention of inspections in the SW bay and did not sign off on having completed the required cleanliness inspection.

Administrative Procedure 0.45 also provides instructions to retrieve foreign material as soon as practicable after cleanliness has been compromised. Contrary to this requirement, no attempt was made to retrieve the pipe fitting dropped into the bay on December 5. Instead, an operability evaluation was performed to demonstrate that the fitting would have no effect on the operation of the SW system. The fitting was subsequently found on the catwalk above the SW intake bay by operators on December 8, 2005.

<u>Analysis</u>. The failure of maintenance personnel to follow the requirements of station procedures is a performance deficiency. The finding is greater than minor because if left uncorrected, the continued introduction of foreign material into the service water intake bay would become a more significant safety concern. The continued failure to implement this program could result in the loss of safety function of a safety-related system. The finding affected the Mitigating Systems and Initiating Events cornerstones since SW is a mitigating system and the loss of SW is an initiating event for Cooper Nuclear Station. A senior reactor analyst was requested to review the finding. Using the Phase 1 worksheet of Inspection Manual Chapter 0609, “Significance Determination Process,” a Phase 2 analysis would ordinarily be required if the finding degraded two cornerstones. However, the analyst determined that, although findings involving SW may affect both the initiating events and mitigation systems cornerstones, this particular finding did not degrade two or more cornerstones. The finding did not contribute to either the likelihood of a scram or the likelihood that mitigation equipment or functions would not be available. As determined by the inspectors, neither the missed QC

inspections nor the foreign material had an effect of increasing the likelihood. Therefore, the analyst concluded (after consultation with the Reactor Inspection Branch of NRR) that use of the Phase 1 worksheet remained appropriate and the finding was of very low safety significance.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion V, 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 and drawings. Administrative Procedure 0.45, "Foreign Material Exclusions Program," Revision 21, requires implementation of Zone 1 FME controls for areas where final inspection of area cleanliness or immediate retrieval of foreign material is not possible. Contrary to this, the licensee failed to control the SW intake bay as a Zone 1 area during modification of the traveling screens. This resulted in the introduction of foreign material into the intake bay, which had the potential to adversely affect the SW system. Because this issue is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2005-08930, this violation is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000298/2005005-01, Failure to Implement Foreign Material Controls for Service Water Intake Bay.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors: (1) reviewed plant procedures, drawings, the UFSAR, TSs, and vendor manuals to determine the correct alignment of the residual heat removal system; (2) reviewed outstanding design issues, operator workarounds, and UFSAR documents to determine if open issues affected the functionality of the residual heat removal 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 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.

- September 26, 2005, Fire Zone 2D, RHR Heat Exchanger 1B Compartment
- October 11, 2005, Fire Zone 11J, Turbine Building North Basement
- October 12, 2005, Fire Zone 9A, Cable Spreading Room
- October 26, 2005, Fire Zone 1A, Reactor Core Isolation Cooling Quadrant
- November 22, 2005, Fire Zone 20A, Service Water Pump Room
- November 22, 2005, Fire Zone 3A, Switchgear Room 1F
- November 22, 2005, Fire Zone 3B, Switchgear Room 1G

Documents reviewed by the inspectors included:

- Cooper Nuclear Station Fire Hazards Analysis Report, June 20, 2002
- Fire Protection Safety Evaluation Report for Cooper Nuclear Station, May 23, 1979
- Cooper Nuclear Station Fire Preplans

The inspectors completed seven samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

.1 Quarterly Inspection

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to assess the training, operator performance, and evaluator's critique. The training scenario involved the loss of offsite power and a reactor scram coincident with a simulated security event. The scenario was performed in conjunction with an emergency preparedness drill conducted on October 13, 2005. Documents reviewed by the inspectors included:

- Emergency Response Organization, Team 2 Drill Scenario, October 13, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Annual Operating Exam

a. Inspection Scope

Following the completion of the annual operating examination testing cycle, which ended the week of December 15, 2005, the inspector reviewed the overall pass/fail results of the annual individual job performance measure operating tests and simulator operating tests administered by the licensee during the operator licensing requalification cycle. Eight separate crews participated in simulator operating tests and job performance measure operating tests, totaling 42 licensed operators. One of the eight crews failed the simulator portion of the examination, with two of the members of that failing crew also failing on individual competencies on the simulator examination. The licensed operators on the one failing crew were successfully remediated prior to shift duties. All of the licensed operators passed the job performance measure portion of the examination. These results were compared to the thresholds established in Manual Chapter 609, Appendix I, "Operator Requalification Human Performance Significance Determination Process."

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the two 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.

- October 20, 2005, Condition Report CR-CNS-2005-7772, Silt Blockage of Both Service Water Discharge Strainers

- November 3, 2005, Condition Report CR-CNS-2005-8111, Reactor Recirculation Pump Motor Generator Set B Spurious Speed Change

The inspectors completed two samples.

b. Findings

Operator response and the root cause regarding the silt blockage of both SW discharge strainers was the subject of a special inspection. The results of that inspection are documented in NRC Inspection Report 05000298/2005015.

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

a. Inspection Scope

The inspectors: (1) reviewed operator logs, plant computer data, and/or strip charts for the evolutions 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.

- September 26, 2005, Reactor Startup from Forced Outage 05-02
- October 20, 2005, Operator Response to Silt Blockage of both Service Water Discharge Strainers

The inspectors completed two samples.

b. Findings

Operator response and the root cause regarding the silt blockage of both SW discharge strainers was the subject of a special inspection. The results of that inspection are documented in NRC Inspection Report 05000298/2005015.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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 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.

- September 26, 2005, Condition Report CR-CNS-2005-07032, Reactor Core Isolation Cooling Level Switch (RCIC-LS-74) Failure

- October 2, 2005, Condition Report CR-CNS-2005-07201, RHR-MOV-MO25A Packing Leakage

- October 20, 2005, Condition Report CR-CNS-2005-07772, Silt Blockage of Both Service Water Discharge Strainers

- November 8, 2005, Condition Report CR-CNS-2005-08227, Larger than Expected Debris Found in Service Water Strainer

The inspectors completed four samples.

b. Findings

Operator response and the root cause regarding the silt blockage of both SW discharge strainers was the subject of a special inspection. The results of that inspection are documented in NRC Inspection Report 05000298/2005015.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed the cumulative effects of operator workarounds to determine: (1) the reliability, availability, and potential for misoperation of a system; (2) if multiple mitigating systems could be affected; (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents; and (4) if the licensee has identified and implemented appropriate corrective actions associated with operator workarounds. Documents reviewed by the inspectors included the operator workaround list dated November 21, 2005.

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 four 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 re-aligned, and deficiencies during testing were documented. The inspectors also reviewed the UFSAR to determine if the licensee identified and corrected problems related to postmaintenance testing.

- September 25, 2005, Replacement of the Mechanical Interlock in the Motor Starter for Valve RHR-MOV-MO13C (Work Order 4463594)

- October 11, 2005, Replacement of the Time Delay Relay for Reactor Equipment Cooling (REC) Pump B (Work Order 4436183)

- November 2, 2005, Replacement of Packing on Service Water Pump A (Work Order 4449400)

- December 3, 2005, Replacement of Hydraulic Accumulator for Control Rod 38-23 (Work Order 4367824)

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the UFSAR, procedure requirements, and TSs to ensure that the three 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) setpoints of annunciators and alarms. The inspectors also verified that the licensee identified and implemented any needed corrective actions associated with the surveillance testing.

- October 5, 2005, Surveillance Test, 6.1RHR.501, “ASME Section XI Periodic Pressure Test of the Class 2 Residual Heat Removal System Loop A,” Revision 10

- October 6, 2005, Surveillance Test, Performance Evaluation Procedure 13.20, “Determination of Fuel Pool Heatup Rate,” Revision 3

- October 31, 2005, Pump Inservice Test, Surveillance Procedure 6.1CS.101, “Core Spray Test Mode Surveillance Operation (IST)(Div 1),” Revision 15

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

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 modification listed below was 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 were 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.

- October 22, 2005, Temporary Sonar System Installation in the Service Water Intake Bay

Documents reviewed by the inspectors included:

- Work Order 4433447, Install Sonar Unit in E Bay
- 10 CFR 50.59 Screening Form, Dated June 29, 2005
- Condition Report CR-CNS-2005-07772, Regarding Clogging of Both Service Water Discharge Strainers
- Engineering Procedure 3.4.4, “Temporary Configuration Change,” Revision 7
- System Operating Procedure 2.2.3.1, “Traveling Screen, Screen Wash, and Sparger System,” Revision 40

The inspectors completed one sample.

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 inspectors reviewed licensee submissions and verified with the licensee that no emergency plan or emergency action level changes were made during calendar year 2005. Inspection Procedure 71114.04 was not performed for the licensee during calendar year 2005 due to lack of opportunity.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

For the drill listed below, and simulator-based training evolutions contributing to drill/exercise performance and emergency response organization performance indicators, the inspectors: (1) observed the training evolution to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities; (2) compared the identified weaknesses and deficiencies against licensee identified findings to determine whether the licensee is properly identifying failures; and (3) determined whether licensee performance is in accordance with the guidance of the Nuclear Electric Institute 99-02, “Voluntary Submission of Performance Indicator Data,” acceptance criteria.

- October 13, 2005, Emergency Response Organization Team 2 Emergency Drill

Documents reviewed by the inspectors included:

C Emergency Response Organization, Team 2 Drill Scenario, October 13, 2005.

The inspectors completed one sample

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Review of Items Entered into the CAP

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 issue 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.

- August 2, 2005, Unplanned Entry Into Technical Specification 3.0.3 Due to REC Leakage

b. Findings

Introduction: A self-revealing, Green NCV was identified regarding the failure to correct a degraded condition on the REC system. This condition contributed to excessive system leakage and rendered both divisions of REC inoperable, requiring an entry into TS 3.0.3.

Description. On August 2, 2005, operators aligned the REC system in order to perform maintenance on the fan coil unit (FCU) located on the 882 foot elevation of the reactor building in the northeast quadrant. The FCU is cooled by REC and is required to support operability of Core Spray Pump A and the reactor core isolation cooling pump. To support the maintenance activity, operators drained the FCU by closing Manual Isolation Valves REC-V-97 and REC-V-98 and opening Drain Valve REC-V-444. However, after sufficient time had passed for the FCU to have completely drained, a steady stream of water was observed coming from Valve REC-V-444. The auxiliary operator performing the alignment left the area to check the REC surge tank level, which is located on elevation 976 of the reactor building. Valve REC-V-444 remained open. When he arrived at the surge tank, the operator found that the level had dropped approximately 2 inches in one hour. This exceeded the operability limit for REC leakage. As a result, the control room declared both divisions of REC inoperable, which required entry into TS 3.0.3. The auxiliary operator immediately returned to the FCU and shut Valve REC-V-444 to isolate the leakage. The control room exited TS 3.0.3 approximately 28 minutes later after verifying operability of REC.

The licensee documented this event in Condition Report CR-CNS-2005-05588, which was categorized as a Category A condition and was the subject of a full root cause evaluation. Based on this evaluation, the licensee concluded that the root cause for the event was an inadequate assessment of the risk associated with the maintenance activity. The inspectors reviewed the daily maintenance risk assessment for August 2, 2005, which did not show a significant increase in core damage frequency due to this maintenance. The risk assessment associated with this work did contribute to the event; however, the inspectors concluded that this was not the root cause.

Notification 10175970 was written in July 2002 to document that Valve REC-V-98 was known to leak and that Valve REC-V-97 was suspected to leak. This was made a “work item only” in the CAP, and Work Order 4252736 was initiated to replace or repair Valve REC-V-98 during Refueling Outage 21 (Spring 2003). According to the licensee’s records review, it was determined that Valve REC-V-98 required replacement; however, the engineering department could not provide the required evaluations in time for Refueling Outage 21. Instead, the valve was disassembled, inspected, and reassembled. There was no postmaintenance test to verify the leakage had been corrected nor was there any documentation of the as-found condition of the valve internals. No documentation of corrective maintenance on Valve REC-V-97 could be located. The work order and CAP documents were subsequently closed. The licensee considered this to be a contributing cause to the event rather than the root cause. Had the leakage through these valves been corrected, operability of the REC system would not have been challenged.

The licensee’s corrective actions for this event included revising the work control process to include a more formal evaluation of “worst case scenarios” associated with maintenance activities. In addition, Valves REC-V-97 and REC-V-98 will be repaired or replaced.

<u>Analysis</u>: The failure to correct a degraded condition on a system necessary to mitigate the consequences of an accident is a performance deficiency. This 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. Using the Manual Chapter 0609, “Significance Determination Process,” Phase 1 Worksheet, the finding is determined to have very low safety significance because the licensee was able to demonstrate that there was no loss of safety function for any mitigating systems and the finding did not screen as risk significant due to external initiating events. The cause of the finding is related to the crosscutting element of problem identification and resolution in that a condition adverse to quality was not corrected in 2003.

<u>Enforcement</u>: Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI, “Corrective Action,” requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this, between July 2002 and August 2005 the licensee failed to correct a condition adverse to quality. Specifically, Manual Isolation Valves REC-V-97 and REC-V-98 were known to leak and were not repaired. On August 2, 2005, these valves were relied upon to maintain system integrity and system operability during a

maintenance activity. Due to the leakage by these valves, the REC system was rendered inoperable. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2005-05588, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2005005-02, Failure to Correct a Degraded Condition Results in Inoperability of the REC System.

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors completed a semiannual trend review of repetitive or closely related issues that were documented in corrective action documents, corrective maintenance documents, and the control room logs to identify trends that might indicate the existence of more safety significant issues. The inspectors' review covered the 6-month period between May and November 2005. When warranted, some of the samples expanded beyond those dates to fully assess the issue. The inspectors also reviewed CAP items associated with SW strainer alarms, abnormal procedure entries, grid stability issues, and motor-operated valve failures. The inspectors compared and contrasted their results with the results contained in the licensee's quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy.

b. Assessment and Observations

The inspectors concluded that the licensee's equipment trending program had improved over the past 6 months. During this time period, the licensee identified and documented a total of 10 adverse equipment trends in their CAP. This was the highest number of trend condition reports seen by the inspectors during a semiannual trend review inspection. However, the inspectors identified an example where the licensee was slow to recognize an adverse trend and initiate corrective actions in their CAP. During a search of the control room logs and the plant computer database, the inspectors observed that the control room received 35 service water strainer high differential pressure alarms during a 20-day period in August 2005. Strainer high differential pressure alarms can be a precursor to the loss of SW, which is a significant event. Condition Report CR-CNS-2005-06831 documented this adverse trend in SW system performance; however, it was not initiated until September 20, 2005. Additionally, this condition report was closed to Condition Report CR-CNS-2005-06797, which was initiated to perform an apparent cause evaluation for various other SW issues, but according to the licensee's CAP procedures, Condition Report CR-CNS-2005-06831 should have been a candidate for a separate root cause evaluation. One month later, on October 20, 2005, both SW discharge strainers became clogged, resulting in all SW being declared inoperable.

In addition, the inspectors identified an equipment issue that was not addressed by the licensee's CAP. During September and October 2005, the control room logged 28 separate notifications from their transmission system dispatcher of entry into Transmission Loading Relief Level 3. This condition existed due to high power transmission loads on a single transmission line between Cooper Nuclear Station and

Saint Joseph, Missouri. Since this condition has the potential to affect grid stability, the dispatcher may request a rapid power reduction from Cooper Nuclear Station, on the order of 30 percent reactor power during a Transmission Loading Relief Level 3. There were no condition reports written to document or trend this condition. The inspectors acknowledged that the licensee has limited control over this aspect of grid operation and this issue is not within the scope of 10 CFR Part 50, Appendix B; however, given the potential to challenge plant stability due to rapid power reductions of this magnitude, the inspectors concluded that it should have been documented and trended in the licensee's CAP.

4OA3 Event Follow-up (71153)

.1 (Closed) Unresolved Item (URI) 05000298/2005004-01: Failure to Perform Scram Actions Results in Level 8 Reactor Feed Pump Trip

a. Inspection Scope

The inspectors performed a followup inspection of URI 05000298/2005004-01, which was opened regarding operator response to a manual reactor scram on September 23, 2005. The inspection included interviews with operations and training department personnel as well as a review of training records and simulator performance reviews.

b. Findings

Introduction. A self-revealing, Green NCV was identified regarding operator response during implementation of the scram response procedure.

Details. NRC Integrated Inspection Report 05000298/2005004 described operator response to the manual reactor scram on September 23, 2005. During the scram recovery actions, operators appropriately entered General Operating Procedure 2.1.5, "Reactor Scram," Revision 52, and carried out the immediate actions in Attachment 1. These included reducing the reactor vessel master level controller setpoint to 15 inches and tripping one reactor feed pump. General Operating Procedure 2.1.5 requires that Attachments 2-5 be entered concurrently; operators must prioritize these actions based on plant conditions. The reactor operator entered Attachment 2 for reactor power control and Attachment 3 for reactor water level control. Attachment 3 requires the operators to take manual control of the operating reactor feed pump and reduce its speed so that its discharge pressure is less than or equal to reactor pressure. The operator incorrectly prioritized the power control actions over the level control actions, which resulted in reactor vessel level reaching the Level 8 setpoint prior to reducing flow from the remaining reactor feed pump. This resulted in the remaining reactor feed pump tripping. Operators were able to restart the feed pump and restore positive level control prior to reaching any other level setpoints.

This error was similar to errors made during scram recovery actions on May 26, 2003 (NRC Integrated Inspection Report 05000298/2003006), and October 16, 2003 (NRC Integrated Inspection Report 05000298/2003007). However, the inspectors concluded that the corrective actions for the previous errors would not necessarily have prevented the error in September 2005. Corrective actions for the most recent error included additional training for all operators, which emphasized monitoring of critical plant parameters during scram recovery actions and correctly prioritizing actions based on those parameters.

The inspectors reviewed the results of the licensee's simulator testing and concluded that simulator response was sufficiently similar to the actual plant response during the scram. Therefore, simulator fidelity did not contribute to this event.

Analysis. The failure to implement scram recovery actions to control reactor vessel level following a scram is a performance deficiency. This finding is greater 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. In this context, the reactor feed pumps are considered to be a mitigating system and the operator's actions caused a loss of the only operating reactor feed pump. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because there was no loss of safety function for the mitigating system and the finding did not screen as risk significant due to external initiating events.

The cause of the finding is related to the crosscutting element of human performance in that it was reasonable to have expected the reactor operator to correctly prioritize the scram actions, which would have prevented the loss of reactor feed. This reactor operator was recently licensed and had not received the same training regarding prioritization of scram actions during his initial licensed operator training that was provided to previously licensed operators during their training cycle.

Enforcement: Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 6(u), requires procedures for reactor trips (scrams). General Operating Procedure 2.1.5, "Reactor Scram," Revision 52, Attachment 3, required operators to take manual control of the operating reactor feed pump and reduce its speed so that its discharge pressure was less than or equal to reactor pressure. Contrary to this requirement, on September 23, 2005, the reactor operator failed to take manual control of the operating reactor feed pump and reduce its speed so that its discharge pressure was less than or equal to reactor pressure. This resulted in reactor vessel level increase to the Level 8 setpoint, which caused the only operating reactor feed pump to trip. The failure to implement this procedure requirement resulted, in part, from the failure to provide recently licensed operators with adequate training on prioritization of scram response actions. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2005-06960, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2005005-03, "Failure to Implement Scram Actions Results in Level 8 Reactor Feed Pump Trip."

.2 (Closed) Licensee Event Report (LER) 05000298/2005-004-00: Loss of Condenser Vacuum Due to Failed Drain Line Results in Manual Scram

This report was submitted in response to a failed turbine bearing oil drain line, which was routed through the main condenser. This resulted in an unacceptable amount of air leakage into the main condenser and lower main condenser vacuum. Unable to maintain vacuum at an acceptable level, operators manually scrammed the reactor. The inspectors reviewed this LER and the licensee's root cause analysis. No violations of NRC requirements were identified regarding the cause of the scram. This LER is closed.

4OA5 Other Activities

.1 (Closed) URI 05000298/2005009-05: Evaluation and Corrective Actions for Emergency Diesel Generator (EDG) Fuel Leaks

NRC Inspection Report 05000298/2005009 documented an unresolved item regarding the licensee's evaluation and corrective actions for leaking fuel oil injector pumps on both EDGs. This item was left unresolved pending completion of an apparent cause determination for the fuel injector pump leaks and the results of an extent of condition inspection of the injector pump drain lines. This information was needed to determine if the licensee's evaluation and corrective actions were adequate as well as to determine if there was any adverse impact on EDG operability. Subsequently, the licensee completed their apparent cause determination and performed inspections of two fuel injection pumps on each EDG as well as inspections of the injector pump drain lines. The licensee was unable to ascertain a cause for the fuel leaks based on their evaluations and inspections; however, they were able to demonstrate that, if the fuel leaks were to recur, they would have a negligible impact on EDG operability. Based on these results, the inspectors identified no performance deficiencies or violations of NRC requirements. This URI is closed.

.2 (Closed) URI 05000298/2005002-08: EDG 1 Oil Leak

a. Inspection Scope

The inspectors completed a follow-up inspection for an unresolved item regarding the past operability of EDG 1 due to a degraded condition on the lube oil system. The inspection included a review of the licensee's evaluation of the EDG's capabilities due to the leak and the licensee's capabilities to perform an emergency repair to the EDG had the leak occurred during an actual demand on the EDG.

b. Findings

Introduction. The inspectors identified a Green NCV regarding inadequate corrective actions for past lube oil leaks on EDG 1, which resulted in the catastrophic failure of a lube oil instrument line on December 30, 2004.

Description. NRC Inspection Report 05000298/2005002 discussed an unresolved item regarding a lube oil instrument line on EDG 1 which failed during a monthly surveillance test on December 30, 2004. The failure of this instrument line resulted in a 7 gpm oil leak and approximately 100-150 gallons of oil were sprayed on the floor and on other support equipment in the EDG room. This item remained unresolved pending further inspection to determine the actual impact on the EDG's capability to perform its safety function.

Based on a review of the vendor manual for the EDG and the alarm response procedures associated with EDG alarms, the inspectors concluded that failure of the EDG due to this condition was credible. Furthermore, the configuration of the instrument line, which made it susceptible to high cycle fatigue failure, had existed since 1989. As a result of this configuration, fittings on the instrument line developed cracks and oil leaks on three separate occasions in 1993, 1995, and 1998. Corrective actions for these three failures consisted only of replacing the fittings. The instrument line was never restored to the vendor's original design, which was not susceptible to high-cycle fatigue.

Analysis. The failure to take corrective actions to prevent recurrence of a significant condition adverse to quality is a performance deficiency. This 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. The Phase 1 worksheets in Manual Chapter 0609, "Significance Determination Process," were used to conclude that a Phase 2 analysis was required because the inspectors determined that, given an accident during the months before the failure, EDG 1 would not have been capable of performing its intended safety function for at least 24 hours. This represented an actual loss of safety function of the single train for greater than the TS allowed outage time of 7 days. The inspectors performed a Phase 2 analysis using Appendix A, "Technical Basis for At-Power Significance Determination Process," of Manual Chapter 0609, "Significance Determination Process," and the Phase 2 worksheets for Cooper Nuclear Station. The inspectors assumed that the duration of the EDG unavailability was approximately 90 days. Additionally, as a Phase 2 bounding assumption, the inspectors assumed that EDG 1 would have been completely incapable of performing its intended function throughout the exposure period and the appropriate credit for the safety function, "Emergency Power (EAC)," during the exposure period was two. This was reduced from a multitrain system credit of three to a single-train credit for the applicable sequences. The most limiting core damage sequence involved a loss of offsite power followed by failure of the remaining EDG and failure to recover offsite power within 4 hours. Based on the results of the Phase 2 analysis, the finding was determined to have substantial safety significance. The senior reactor analyst's review of the Phase 2 analysis determined that a more detailed Phase 3 analysis was needed to fully assess the safety significance. Based on the results of the Phase 3 analysis, the finding is determined to have very low safety significance. The Phase 3 analysis is included as Attachment 2 to this report.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality 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 actions taken to preclude repetition. Contrary to this, between 1993 and December 30, 2004, the licensee failed to take corrective actions to preclude repetitive failures of an instrument line on the lube oil system for EDG 1. Specifically, the instrument line was configured such that it was susceptible to high-cycle fatigue failures. Cracks developed in the instrument line fittings on three separate occasions due to this configuration, but corrective actions only replaced the fittings; the configuration of the line was never changed to preclude recurrence of the cracks. This resulted in the catastrophic failure of the line on December 30, 2004. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2004-07947, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2005005-04, Ineffective Corrective Action Results in Emergency Diesel Generator Inoperability (EA-05-172).

.3 (Closed) URI 05000298/2005002-07: SW Pump A 4160 V Breaker Failure

a. Inspection Scope

The inspectors completed a followup inspection for an unresolved item regarding the failure of the 4160 V break for SW Pump A to close on demand. The issue remained unresolved to further review the impact this failure had on overall system operability.

b. Finding

Introduction: A self-revealing, Green NCV was identified regarding inadequate corrective actions for the failure of a safety-related 4160 V breaker. This resulted in a repetitive failure of the breaker.

Details: NRC Integrated Inspection Report 05000298/2005002 described the failure of the 4160 V Magne-Blast breaker for SW Pump A to close on demand from the control room. This occurred on December 29, 2004. After further review of the root cause analysis, the inspectors concluded that a performance deficiency existed in that the failure mechanism, inadequate clearance between the prop pin and the breaker frame, was a condition which had caused the previous failure of at least one other safety-related 4160 V Magne-Blast breaker in December 2000. The inadequate clearance resulted from progressive movement of the prop pin during breaker operation. Corrective actions, including the addition of spacers between the prop pin and the breaker frame to assure adequate clearance, were proposed following the failure in 2000, but these corrective actions were never implemented. This resulted in the additional breaker failure in 2004. The inspectors were unable to determine why these corrective actions were never implemented.

The licensee stated that the root cause for the prop pin misalignment was a misalignment of the collapsible arm mechanism in the breaker combined with a high number of duty cycles on the breaker. To correct this, the breaker which failed in 2004 was refurbished to restore adequate clearance between the prop pin and breaker frame as well as to ensure correct alignment of the collapsible arm. The licensee also performed inspections of the remaining population of safety-related 4160 V Magne-Blast breakers to ensure proper alignment of these components. No discrepancies were found during these inspections. Additionally, the breaker maintenance program was revised to include specific inspection criteria for prop pin clearance and correct alignment of the collapsible arm mechanism.

In order to address the potential for this failure to occur on high duty cycle breakers, the licensee formulated a corrective action which required a revision to the preventive maintenance frequency. The revision would have required inspections every 100 breaker cycles or every 4.5 years. The licensee estimated that this condition based maintenance interval would result in the inspection of SW pump breakers on an annual basis. The required evaluations and supporting documentation for this change were completed and this corrective action was closed on June 23, 2005; however, the maintenance interval was not actually changed in the work management system. Therefore, the SW pump breakers have not received the annual inspection that would have been required by this corrective action. The inspectors discussed this with the licensee and a new condition report (CR-CNS-2006-00834) was written to re-evaluate this corrective action. The inspectors concluded that this did not represent an immediate safety concern since industry standards define “high duty cycle” as 200 cycles per year; the maintenance interval of 100 cycles was a conservative decision based on engineering judgement.

Analysis: The failure to take corrective actions to prevent recurrence of a significant condition adverse to quality is a performance deficiency. This 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. In addition, the finding is also associated with the Initiating Events cornerstone attribute of equipment performance and affects the associated cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The Phase 1 worksheets in Manual Chapter 0609, “Significance Determination Process,” were used to conclude that a Phase 2 analysis was required because two reactor safety cornerstones were affected. 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 breaker would not have properly closed on demand during the 2 days, 11 hours from the time it was last closed until the failure to latch on December 29. Additionally, the initiating event likelihood for the loss of service water system special initiator was increased from six to five to reflect the fact that the finding increased the likelihood of a loss of SW, a normally cross-tied support system. The most limiting core damage sequence involved the loss of SW followed by a failure of reactor core isolation cooling, high pressure coolant injection, or the failure of late injection using the control rod drive pumps. Based on the results of the Phase 2 analysis, the finding was determined to be of low to moderate safety significance. The senior reactor analyst's review of the Phase 2 analysis determined that a more detailed Phase 3 analysis was needed to fully assess the safety significance. Based on the results of the Phase 3 analysis, the finding is determined to have very low safety significance. The Phase 3 analysis is included as Attachment 3 to this report.

The cause of the finding is related to the crosscutting element of problem identification and resolution. The inadequate corrective actions that resulted in a repetitive breaker failure occurred 6 years ago and are not necessarily indicative of current performance; however, a corrective action designed to prevent recurrence of the failure in 2004 was not implemented and is indicative of current performance.

Enforcement. Part 50 of Title 10 of the Code of Federal Regulations, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality 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 actions taken to preclude repetition. Contrary to this, between December 2000 and December 2004, the licensee failed to take corrective actions to preclude a repetitive failure of a safety-related 4160 V breaker due to misalignment of internal components. Specifically, a safety-related 4160 V breaker failed in December 2000 due to inadequate clearance between the prop pin and breaker frame. The misalignment was due to progressive movement of the prop pin during breaker operation. Corrective actions were proposed to insert spacers to assure that adequate clearance was maintained, but these corrective actions were never implemented. As a result, an additional safety-related 4160 V breaker failed in December 2004 due to the same cause. Because the finding is of very low safety significance and has been entered into the licensee's CAP as Condition Report CR-CNS-2004-07938, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2005005-05, Ineffective Corrective Action Results in the Failure of a Safety-Related 4160 V Breaker.

4OA6 Meetings, Including Exit

On January 5, 2005, 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.

On December 28, 2005, the emergency preparedness inspector conducted a telephonic meeting with Mr. J. Bednar, Emergency Preparedness Manager, to verify the licensee had not made changes to its emergency plan or emergency action levels during calendar year 2005.

On January 23, 2006, the operations examiner discussed the results of the annual operations exam inspection with Mr. Dave Werner, Requal Supervisor. The licensee acknowledged the findings presented.

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
T. Chard, Manager, Radiation Protection
R. Edington, Vice President
S. Blake, Manager, Quality Assurance
K. Fili, Manager, Nuclear Projects
D. Kimbell, Outage Manager
G. Kline, Director, Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2005005-01	NCV	Failure to Implement Foreign Material Controls for Service Water Intake Bay (Section 1R04)
05000298/2005005-02	NCV	Failure to Correct a Degraded Condition Results in Inoperability of the Reactor Equipment Cooling System (Section 4OA2)
05000298/2005005-03	NCV	Failure to Implement Scram Actions Results in Level 8 Reactor Feed Pump Trip (Section 4OA3)
05000298/2005005-04	NCV	Ineffective Corrective Action Results in Emergency Diesel Generator Inoperability (Section 4OA5)
05000298/2005005-05	NCV	Ineffective Corrective Action Results in the Failure of a Safety Related 4160 V Breaker (Section 4OA5)

Closed

05000298/2005004-01	URI	Failure to Perform Scram Actions Results in Level 8 Reactor Feed Pump Trip (Section 4OA3)
05000298/2005004-00	LER	Loss of Condenser Vacuum Due to Failed Drain Line Results in Manual Scram (Section 4OA3)
05000298/2005009-05	URI	Evaluation and Corrective Actions for Emergency Diesel Generator Fuel Leaks (Section 4OA5)
05000298/2005002-08	URI	EDG 1 Oil Leak (Section 4OA5)
05000298/2005002-07	URI	SW Pump A 4160 V Breaker Failure (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Updated Final Safety Analysis Report for Cooper Nuclear Station

Technical Specifications for Cooper Nuclear Station

Administrative Procedure 0.45, "Foreign Material Exclusion Program," Revision 21

Procedure 2.2A RHR. DIV2; "Residual Heat Removal System Component Checklist," Revision 1

Procedure 2.2B RHR DIV 2; "Residual Heat Removal System Instrument Valve Checklist," Revision 0

Drawing 2040, "Flow Diagram Residual Heat Removal Sys Loop "B"," Revision N13

Condition Reports:

CR-CNS-2004-04683	CR-CNS-2005-00767	CR-CNS-2005-03419
CR-CNS-2004-05882	CR-CNS-2005-00974	CR-CNS-2005-03777
CR-CNS-2004-07020	CR-CNS-2005-01050	CR-CNS-2005-04683
CR-CNS-2004-07021	CR-CNS-2005-02378	CR-CNS-2005-06426
CR-CNS-2004-07576	CR-CNS-2005-02735	

Section 4OA2

Cooper Nuclear Station Equipment Trend Report, May through October 2005

Control Room Logs for June 21, through November 21, 2005

Condition Reports:

CR-CNS-2005-06831	CR-CNS-2005-07871	CR-CNS-2005-07629
CR-CNS-2005-03632	CR-CNS-2005-07861	CR-CNS-2005-07758
CR-CNS-2005-03700	CR-CNS-2005-07848	CR-CNS-2005-07911
CR-CNS-2005-03701	CR-CNS-2005-07763	CR-CNS-2005-00815
CR-CNS-2005-03710	CR-CNS-2005-07742	CR-CNS-2005-00890
CR-CNS-2005-03791	CR-CNS-2005-07457	CR-CNS-2005-01759
CR-CNS-2005-03860	CR-CNS-2005-07361	CR-CNS-2005-01803
CR-CNS-2005-03935	CR-CNS-2005-07339	CR-CNS-2005-02084
CR-CNS-2005-04145	CR-CNS-2005-07225	CR-CNS-2005-02471
CR-CNS-2005-04914	CR-CNS-2005-07040	CR-CNS-2005-04025
CR-CNS-2005-07024	CR-CNS-2005-06740	CR-CNS-2005-04503
CR-CNS-2005-08175	CR-CNS-2005-06734	CR-CNS-2005-04657
CR-CNS-2005-08144	CR-CNS-2005-06726	CR-CNS-2005-06877
CR-CNS-2005-08064	CR-CNS-2005-06724	CR-CNS-2005-07318
CR-CNS-2005-08000	CR-CNS-2005-06722	CR-CNS-2005-0v7669
CR-CNS-2005-07999	CR-CNS-2005-06603	CR-CNS-2005-08074
CR-CNS-2005-07983	CR-CNS-2005-06586	CR-CNS-2005-08252
CR-CNS-2005-07886	CR-CNS-2005-07466	

LIST OF ACRONYMS

CAP	corrective action program
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
FCU	fan coil unit
FME	foreign material exclusion
LER	licensee event report
NCV	noncited violation
QC	quality control
REC	reactor equipment cooling
SSC	structure, system, and component
SW	service water
TSs	Technical Specifications
QC	quality control
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
V	volt

ATTACHMENT 2
FINAL SIGNIFICANCE DETERMINATION
Cooper Nuclear Station Emergency Diesel Generator Oil Line Failure
Phase 3 Estimation

Performance Deficiency:

The licensee modified a lubricating oil pressure instrument line on Diesel Generator 1 in 1989. The modified instrument line was “field-routed” and configured such that the line was susceptible to vibration-induced high-cycle fatigue. The line developed cracks and leaks in 1993, 1995, and 1998 before failing catastrophically on December 30, 2004, during a monthly surveillance run, thus rendering Diesel Generator 1 not functional. The inspectors determined that the corrective actions for the failures in 1993, 1995, and 1998 were inadequate in that they did not prevent the failure in 2004.

Phase 1 Screening Logic, Results, and Assumptions:

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, “Issue Screening,” the inspectors determined that the failure to properly design and configure the lubricating oil line was a licensee performance deficiency because the configuration resulted in a failure of Diesel Generator 1 that was within the control of the licensee. The issue was more than minor because the reliability of Diesel Generator 1 is associated with the equipment performance attribute and adversely affects the mitigating systems cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations.” The inspectors determined that, given an accident during the months before the failure, Diesel Generator 1 would not have been capable of performing its intended safety function for at least 24 hours. This represented an actual loss of safety function of the single train for greater than the Technical Specification allowed outage time of 7 days. Therefore, the issue was passed to Phase 2 for risk estimation.

Phase 2 Estimation:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, “User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Cooper Nuclear Station, Revision 1. The assumptions made included the following:

- The exposure time was approximately 90 days. Therefore, the exposure time window of greater than 30 days was used. Given a postulated accident, Diesel

Generator 1 would have failed to complete its 24-hour mission time since September 2004, the time at which 24 hours of cumulative run time had occurred prior to the break.

- As a Phase 2 bounding assumption, the inspectors assumed that Diesel Generator 1 would have been completely incapable of performing its intended function throughout the exposure period.

- The appropriate credit for the safety function, "Emergency Power (EAC)," during the exposure period was 2. This reduced from a multitrain system credit of 3 to a single-train credit for the applicable sequences.

The inspectors evaluated the loss of offsite power worksheet given the above assumptions. Using the counting rule worksheet, this finding was estimated to be YELLOW. However, because several assumptions made during the Phase 2 process were overly conservative, a Phase 3 evaluation is required. Therefore, the senior reactor analyst performed a Phase 3 analysis in accordance with Manual Chapter 0609, Appendix A, Attachment 1, in the section entitled: "Phase 3 - Risk Significance Estimation Using Any Risk Basis That Departs from the Phase 1 or 2 Process."

Phase 3 Evaluation:

The analyst noted that Diesel Generator 1 would not necessarily have failed immediately upon demand throughout the exposure period as assumed during the Phase 2 estimation. Any time that a diesel generator runs and carries load following a loss of offsite power provides additional time to recover offsite power and/or the redundant diesel generator prior to a station blackout. Therefore, the analyst evaluated the impact of the assumed failure time of Diesel Generator 1 during a postulated loss of offsite power as the method of conducting a Phase 3 analysis. The conditional core damage probability developed using a Standardized Plant Analysis Risk (SPAR) model simulation was multiplied by the station blackout likelihood during each of the exposure time windows. During this evaluation, the following analyst assumptions were utilized:

- The industry frequency-weighted average loss of offsite power initiating event likelihood, adjusted for the region containing the Cooper Nuclear Plant, is 3.31×10^{-2}/yr.

- The condition, caused by the subject performance deficiency, existed for several years following the installation of the modified oil line. However, the condition only affected the capability of Diesel Generator 1 from September 9, 2004 (the date that the machine first would have run for less than 24 hours prior to failure, as calculated by the analyst) and December 31, 2004, when Diesel Generator 1 was repaired.

- Diesel Generator 1 would have continued to operate for 40 minutes following receipt of the low level alarm as stated in an evaluation performed by the licensee.

- Operators could not have recovered Diesel Generator 1 prior to the onset of core damage. However, given the 8-hour coping time at Cooper Nuclear Station, the analyst assumed that repair of the lubricating oil system was possible. The probability of nonrecovery was calculated as 0.561. The calculation of this value was dominated by the following probabilities:

  < Operators Fail to Trip Diesel Generator 1 Prior to Irreparable Damage
  < Technical Support Center Fails to Prioritize Work on Diesel Generator 1
  < Warehouse Fails to Identify the Proper Fitting during Blackout

The Cooper SPAR model, Revision 3.11, was used to quantify the conditional core damage probability given that a station blackout occurs. This value (4.61×10^{-2}) was then multiplied by the likelihood of a station blackout for each time window. The calculation of these likelihoods included credit for the time that Diesel Generator 1 would have run following a demand, the mean time to failure of Diesel Generator 2, and the probability that offsite power would be restored prior to failure of both diesel generators. The total change in core damage frequency, without recovery of Diesel Generator 1, was determined to be 1.41×10^{-6}. This value was multiplied by the nonrecovery probability calculated for repairs on Diesel Generator 1 to obtain the total internal change in core damage frequency of 7.91×10^{-7}.

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 Significance Determination Process result provided a Risk Significance Estimation of 7 or greater. The analyst reviewed potential external initiators at the Cooper Nuclear Station and determined that none impacted this finding sufficiently to increase the color of the finding as determined by internal initiators alone.

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.6, "Screening for the Potential Risk Contribution Due to LERF," the analyst assessed the impact of large early release frequency because the Phase 2 Significance Determination Process result provided a risk significance estimation of 7. The analyst noted that the dominant core damage sequences affected by the subject performance deficiency were not large early release frequency (LERF) contributors. As such, the NRC's best estimate determination of the change in LERF resulting from the performance deficiency was zero.

Therefore, the analyst determined that the subject performance deficiency represented a finding of very low risk significance. This was based on a Phase 3 evaluation performed in accordance with NRC Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations."

ATTACHMENT 3
FINAL SIGNIFICANCE DETERMINATION
Cooper Nuclear Station Service Water Pump Breaker Failure
Modified Phase 2 Estimation

IV. Performance Deficiency:

Licensee personnel failed to take corrective action to ensure appropriate prop pin clearance was maintained for a safety-related breaker installed in the Service Water Pump A cubicle. The resulting misalignment of subcomponents in this 4160 V Magne-Blast brand breaker eventually caused the failure of Service Water Pump A to start on demand during routine operations in December 2004.

II. Safety Significance:

The analyst determined that the performance deficiency represented a finding of very low risk significance. This was based on a modified Phase 2 evaluation performed in accordance with Inspection Manual Chapter 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations.” The analyst estimated the change in core damage frequency (ΔCDF) resulting from this performance deficiency to be 2.56×10^{-7} (validated with 6.28×10^{-7} from SPAR) for internal initiators and 3.26×10^{-7} for external initiated events. Therefore, the total ΔCDF of 5.8×10^{-7} was below the Green/White threshold of 1×10^{-6}.

III. Background:

On December 29, 2004, at 7:28 p.m., control room operators attempted to start Service Water Pump A from the control room. During the attempt, the circuit breaker closed and then immediately tripped open. As a result, Service Water Pump A was declared inoperable in accordance with Technical Specification 3.7.2. The pump had last been successfully started at 8:34 a.m. on December 27 for routine pump rotation.

The circuit breaker for Pump A is a 4160 V General Electric Magne-Blast breaker. Troubleshooting on the breaker by the licensee and by the original equipment manufacturer indicated that a critical clearance between the prop pin and the breaker frame was inadequate. There was also evidence that the prop pin had come in contact with the frame which would have prevented the breaker from latching in the closed position during operation. The breaker had been overhauled by a vendor in January 2000 and, during receipt inspection by the licensee, the prop pin clearance was verified to be adequate. The licensee determined that, although the clearance was adequate in 2000, insufficient spacers between the prop pin and frame allowed the prop pin to travel along its shaft during breaker operation until it contacted the frame.

In December 2000, Resolve Condition Report 2000-1165 documented a similar failure of Service Water Booster Pump B caused by inadequate clearances between the prop pin and frame. This breaker had also been overhauled by the same vendor and the licensee was able to verify that the prop pin clearance was adequate following overhaul, but inadequate spacers had allowed the pin to travel along the shaft and become misaligned during successive breaker operations. As a result, the licensee's breaker engineer recommended the addition of washers between the pin and frame to ensure the critical clearance was maintained. In addition, the entire population of safety-related breakers were inspected, including the breaker for Service Water Pump A, to ensure that adequate clearance existed between the pin and frame; however, the work request to perform this inspection did not require the verification or addition of adequate spacers. The breaker for Service Water Pump A was verified to have adequate clearances during this inspection, but no spacers were added to ensure the clearance was maintained.

IV. <u>Initial Characterization of Risk</u>:

<u>Minor Determination</u>:

In accordance with NRC Inspection Manual Chapter 0612, Appendix B, "Issue Screening," the inspectors determined that the failure to ensure that appropriate prop pin clearance was maintained for the subject breaker was a licensee performance deficiency. Additionally, the failure to identify and correct the clearance problems was fully within the licensee's abilities to control. The inspectors determined that the issue was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events. Specifically, Service Water Pump A would not have responded to a demand to start for a period of time.

<u>Phase 1 Screening</u>:

The inspectors evaluated the issue using the SDP Phase 1 Screening Worksheet for the Initiating Events, Mitigating Systems, and Barriers Cornerstones provided in Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." This issue caused an increase in the likelihood of an initiating event, namely loss of service water, as well as increasing the probability that the service water system would not be available to perform its mitigating systems function. Therefore, the issue was passed to Phase 2, because it affected two cornerstones.

V. <u>Phase 2 Estimation</u>:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, "User Guidance for Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors evaluated the subject finding using the Risk-Informed Inspection Notebook for Cooper Nuclear Station, Revision 1. The following assumptions were made:

- The deficiency in the Pump A breaker increased the likelihood that all service water would be lost because the pump would not have started upon the failure of Pump C.

- The breaker would not have properly closed on demand during the 2 days 11 hours from the time it was last closed until the failure to latch on December 29. Therefore, the exposure time used was < 3 days.

- The initiating event likelihood credit for the loss of service water system special initiator was increased from six to five by the Senior Reactor Analyst in accordance with Usage Rule 1.2 in Manual Chapter 0609, Appendix A, Attachment 2, “Site Specific Risk-Informed Inspection Notebook Usage Rules.” This change reflects the fact that the finding increased the likelihood of a loss of service water, a normally cross-tied support system.

- The deficiency in the Pump A breaker did not increase the probability that the system function would be lost on demand because Pump C was available to provide flow to Division I and was unaffected by the finding. In accordance with Usage Rule 1.2 in Manual Chapter 0609, Appendix A, Attachment 2, all worksheet sequences affected were solved, giving full mitigation credit.

- The functions affected by a loss of service water are containment heat removal (CHR), containment venting (CV), high pressure injection (HPI), and emergency AC power (EAC).

Table 2 of the risk-informed notebook requires that all initiating event scenarios be evaluated when a performance deficiency affects the service water system. The dominant sequences from the notebook are provided in Table 1.

Table 1: Phase 2 Core Damage Sequences

Initiating Event	Sequence Number	Sequence	Estimated Likelihood
Loss of Service Water	1	RECSW24-LI	7
	2	RCIC-LI	7
	3	RCIC-HPCI	7
Transient with Loss of PCS	2	CHR-CV	8
	4	HPI-DEP	8
	1	CHR-LI	9
Stuck Open Relief Valve	4	HPI-DEP	8
	2	CHR-CV	9
Medium-Break LOCA	4	HPI-DEP	9
Loss of Offsite Power	4	HPI-DEP	8
	6	EAC-RLOOP4H	8
	2	CHR-CV	9
Loss of Instrument Air	1	CHR-LI	9
	4	HPI-DEP	9
Loss of Vital 4160V Bus F	1	CHR	9
Loss of Vital 4160V Bus G	1	CHR	9

Loss of Vital DC Bus A	4	HPI-DEP	8
	2	CHR-CV	9
Loss of Vital DC Bus B	4	HPI-DEP	8
	2	CHR-CV	9

Using the counting rule worksheet, this finding was estimated to be of low to moderate safety significance (White). However, because several assumptions made during the Phase 2 process were overly conservative, a Phase 3 (modified Phase 2) evaluation was required.

VI. Modified Phase 2 Estimation

The analyst reviewed the results from the Phase 2 estimation and determined that both the initiating event frequency and the exposure window were overestimated. To better estimate these parameters, the analyst quantified the results from the notebook and documented the ΔCDF in Table 3.

Table 2: Phase 2 Quantification			
Number of Sequences	Sequence Value	Quantification	Factor of 3.33
3	7	3×10^{-7}	9.99×10^{-7}
7	8	7×10^{-8}	2.33×10^{-7}
10	9	1×10^{-8}	3.33×10^{-8}
TOTAL ΔCDF:		3.8×10^{-7}	1.27×10^{-6}

The analyst also quantified the estimated ΔCDF specifically related to a loss of service water (ΔCDF_{TSW}) to facilitate reassessment of the initiating event frequency. The following calculations were conducted:

$$\Delta CDF_{TSW} = (3 \text{ Sequences} * 1 \times 10^{-7}) * 3.33$$

$$= 9.99 \times 10^{-7}$$

$$\Delta CDF_{OTHER} = \Delta CDF - \Delta CDF_{TSW}$$

$$= 1.27 \times 10^{-6} - 9.99 \times 10^{-7} = 2.7 \times 10^{-7}$$

Adjustment of Initiating Event Likelihood:

In accordance with Manual Chapter 0609, Appendix A, Attachment 2, “Site Specific Risk-Informed Inspection Notebook Usage Rules,” the Phase 2 estimation included an increase in the loss of service water initiating event frequency by an order of magnitude. The analyst adjusted this approximation.

Using data taken from Table 3-1 of NUREG/CR-5750, “Rates of Initiating Events at U. S. Nuclear Power Plants: 1987-1995,” February 1999, the analyst calculated the new initiating event likelihood, $IEL_{(TSW\text{-}case)}$. Given the Cooper specific system alignment, the failure of one standby pump, $P_{(C)}$, was assumed to cause a partial loss of service water (IEL_{PTSW}). The analyst quantified the SPAR ESW-MDP1C fault tree to determine the probability that Pump C would fail in standby for some reason. So, the failure of Pump C and the loss of a specific train (Division II) of service water were assumed to cause a total loss of service water initiating event. Therefore, the change was calculated as follows:

$$IEL_{(TSW\text{-}case)} = IEL_{(TSW)} + [\ \tfrac{1}{2} * IEL_{(PTSW)} * P_{(C)}\ ]$$

$$= 9.72 \times 10^{-4/}/yr + [0.5 * 8.92 \times 10^{-3}/yr * 2.26 \times 10^{-2}\ ]$$

$$= 1.07 \times 10^{-3}/\ yr$$

This represented a change in initiating event likelihood of 10.4%. The baseline initiating event likelihood, documented in the risk-informed notebook (IEL_{TSW}), was 2.1×10^{-4}/yr. The increase (ΔIEL_{TSW}) was calculated as follows:

$$\Delta IEL_{TSW} = IEL_{TSW} * \text{Percent Change}$$

$$= 2.1 \times 10^{-4}/yr * 0.104 = 2.18 \times 10^{-5}/yr$$

The revised estimation was then calculated as follows:

$$IEL_{(TSW\text{-}case)} = \Delta IEL_{TSW} + IEL_{TSW}$$

$$= 2.18 \times 10^{-5}/yr + 2.1 \times 10^{-4}/yr$$

$$= 2.32 \times 10^{-4}/yr$$

$$\Delta CDF_{IEL\text{-}ADJUST} = \Delta CDF_{TSW} \div 10 \div IEL_{TSW} * IEL_{(TSW\text{-}case)} + \Delta CDF_{OTHER}$$

$$= 9.99 \times 10^{-7} \div 10 \div 2.1 \times 10^{-4}/yr * 2.32 \times 10^{-4}/yr + 2.7 \times 10^{-7}$$

$$= 3.80 \times 10^{-7}$$

<u>Adjustment of Exposure Time</u>:

In accordance with the site-specific risk-informed inspection notebook approach, exposure times are grouped into orders of magnitude. The “Usage Rules,” Phase 2, estimation calculates an entire range of exposure times as the highest exposure time in that group. For the group of 1/100th of a year (< 3 days), the calculated exposure time is 87.6 hours. The analyst adjusted this approximation to account for the actual exposure time of 59 hours.

$$\Delta CDF_{ADJUST} = \Delta CDF_{IEL\text{-}ADJUST} \div 87.6 \text{ hours} * 59 \text{ hours}$$

$$= 3.80 \times 10^{-7} \div 87.6 * 59$$

$$= 2.56 \times 10^{-7}$$

Validation of Risk-Informed Notebook Results:

The analyst used the SPAR Revision 3.20 model to validate the Phase 2. The loss of service water initiator, TSW, was increased from 4 x 10^{-4}/yr to 4.416 x 10^{-4}/yr and the basic event for a Service Water Pump C (a surrogate for Pump A) failure to start (ESW-MDP-FS-1C) was set to the house event "TRUE." In addition, the nonrecovery probabilities that coincide with the battery depletion time (OEP-XHE-XL-NR04H and EPS-XHE-XL-NR04H) were decreased to represent an 8-hour battery depletion time vice a 4-hour battery depletion time in both the baseline and the case models. The resulting run indicated a ΔCDF of 9.33 x 10^{-5}/yr. The analyst calculated the ΔCDF over the exposure window as 6.28 x 10^{-7}. This value was approximately a factor of 2 different from the result using the risk-informed notebook. Therefore, the Phase 3 value of 2.56 x 10^{-7} was considered valid.

External Initiating Events:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.5, "Screening for the Potential Risk Contribution Due to External Initiating Events," the analyst assessed the impact of external initiators because the Phase 2 SDP result provided a Risk Significance Estimation of 7 or greater.

Seismic, High Winds, Floods, and Other External Events:

The analyst determined, through plant walkdown, that all the major divisional and redundant equipment associated with the service water system were located on the same physical elevation. All four service water pumps are located in the same room at the same elevation. Both primary switchgear are at the same elevation and in adjacent rooms. Therefore, the likelihood that internal or external flooding and/or seismic events would affect one pump or switchgear without affecting the other was considered to be extremely low. Likewise, high wind events and transportation events were assumed to affect all redundant equipment equally.

Fire:

The analyst evaluated the list of fire areas documented in the IPEEE Report, and concluded that internal fires could affect service water system equipment in such a way that the importance of Pump A was increased. These fires would constitute a change in risk associated with the finding. As presented in Table 4, the analyst identified two fire areas of concern: pump room fires and a fire in Switchgear 1G. Given that all four service water pumps are located in one room, three different fire sizes were evaluated, namely: one-pump, three-pump, and four-pump fires.

In the IPEEE Report - Cooper Nuclear Station, the licensee calculated the risk associated with fires in the service water pump room (Fire Area 20A). The probabilities and affects of these fires were documented in NRC Inspection Report 05000298/2004014 and are presented here as follows:

Table 3: Service Water Pump Room Fire Probabilities		
Parameter	Variable	Probability
Fire Ignition Frequency	L_{Fire}	6.55×10^{-3}/yr
Conditional Probability of a Large Oil Spill	$P_{Large\ Spill}$	0.18
Conditional Probability of Fire less than 3 minutes	$P_{Short\ Fire}$	0.10
Conditional Probability of Unsuccessful Halon	P_{Halon}	0.05
Probability of Losing a Pump Other than Pump A in a One Pump Fire	P_{1-1}	0.75
Probability of Losing all Pumps Except Pump A in a Three Pump Fire	P_{3-3}	0.25
Conditional Probability that Pump C is Running (Winter Months)	P_{run-C}	0.5
Conditional Probability of Losing Pump C Given a Fire Damaging a Single Pump	P_{Pump-C}	0.25
Failure to Run Likelihood for a Service Water Pump	L_{FTR}	3.0×10^{-5}/hr
Failure to Start Probability per Demand for a Service Water Pump	P_{FTS}	3.0×10^{-3}

As described in the IPEEE, the licensee determined that there were three different potential fire scenarios in the service water pump room, namely: a fire damaging one pump, caused by a small oil fire; a fire that results from the spill of all the oil from a single pump that damages three pumps; and fires that affect all four pumps. The licensee had determined that fires affecting only two pumps were not likely. The analyst determined that a four-pump fire was part of the baseline risk; therefore, it would not be evaluated.

The IPEEE stated that a single pump would be damaged in an oil fire that resulted from a small spill of oil, $L_{One\ Pump}$. The analyst, therefore, calculated the likelihood that a fire would damage a single pump as follows:

$$L_{One\ Pump} = L_{Fire} * (1 - P_{Large\ Spill})$$

$$= 6.55 \times 10^{-3}/yr * (1 - 0.18)$$

$$= 5.37 \times 10^{-3}/yr$$

As in the IPEEE, the analyst assumed that all pumps would be damaged in an oil fire that resulted from a large spill of oil, that lasted for less than 3 minutes, if the halon system failed to actuate. It should be noted that the intensity of an oil fire is based on the availability of oxygen, and the fire is assumed to continue until all oil is consumed or it is extinguished. Therefore, the shorter the duration of the fire, the higher its intensity and the more likely it is to damage equipment in the pump room. Should the fire last for less than 3 minutes and the halon system successfully actuate, or if the fire lasted for longer than 3 minutes, the licensee determined that a single pump would survive the fire, $L_{Three\ Pumps}$. The analyst, therefore, calculated the likelihood that a fire would damage three pumps as follows:

$$L_{Three\ Pumps} = [L_{Fire} * P_{Large\ Spill} * P_{Short\ Fire} * (1 - P_{Halon})] + [L_{Fire} * P_{Large\ Spill} * (1 - P_{Short\ Fire})]$$

$$= [6.55 \times 10^{-3}/yr * 0.18 * 0.10 * (1 - 0.05)] + [6.55 \times 10^{-3}/yr * 0.18 * (1 - 0.10)]$$

$$= 1.17 \times 10^{-3}/yr$$

The likelihood of Pump C being damaged in a one-pump fire while it is running, $L_{pump\text{-}C}$ was calculated as follows:

$$L_{Pump\text{-}C} = (L_{One\ Pump} * P_{Pump\text{-}C})$$

$$= (5.37 \times 10^{-3}/yr * 0.25)$$

$$= 1.34 \times 10^{-3}/yr$$

The analyst assessed the extent to which a one-pump fire could impact plant risk. A one-pump fire would not automatically result in a plant transient. Plus, the probability that the other two pumps failed during the allowed outage time for the first failure is low. If Pump C failed while running, Division I service water would be lost. The likelihood of a one-pump fire affecting Pump C while it is running and resulting in a loss of service water can be calculated as follows:

$$L_{LOSWS\text{-}PumpC} = L_{One\ Pump} * P_{Pump\text{-}C} * P_{run\text{-}C} * IEL_{(PTSW)}$$

$$= 5.37 \times 10^{-3}/yr * 0.25 * 0.5 * 8.92 \times 10^{-3}/yr * 1\ yr$$

$$= 5.99 \times 10^{-6}/yr$$

This represented an increase in the probability of a loss of service water event over the exposure period.

<u>Loss of Pump C</u>: If Pump C failed from fire while in standby, there would be no immediate impact on the system because the Pump A breaker would not be required to close. The baseline core damage frequency for this fire was calculated by analyzing the risk associated with the loss of one pump of service water for the 30-day period assumed to be required to repair a fire-damaged pump. The result in SPAR was a core damage frequency of 2.21×10^{-4}/yr. The case was calculated assuming that a fire damaged Pump C and Pump A would not start. A 30-day window was again used, although this is clearly bounding for the breaker failure. The resulting core damage frequency was 3.068 x 10^{-3}/yr. Using a 30-day exposure for the fire results in a ΔCDF probability of 2.34×10^{-4} over the 30-day period.

If Pumps B or D were to fail in a one-pump fire while Pump C was in service, failure of the redundant pump and Pump C would cause a loss of service water initiating event.

The analyst determined that the resulting frequency would be at least two orders of magnitude lower than the fire-induced loss of Pump C because two divisional components would also have to fail. Therefore, this scenario was considered to cause a negligible risk increase.

Loss of Three Pumps: The analyst concluded that a three-pump fire not involving Pump A, would result in a loss of service water system initiating event. The likelihood of having a loss of all service water as a result of a three-pump fire, $L_{3P\ LOSWS}$, is then calculated as follows:

$$L_{3P\ LOSWS} = L_{Three\ Pumps} * P_{3\text{-}3} * P_{run\text{-}C}$$

$$= 1.17 \times 10^{-3}/yr * 0.25 * 0.5$$

$$= 1.47 \times 10^{-4}/yr$$

The analyst used the SPAR model to quantify the conditional core damage probability for a fire that takes out Pumps B, C, and D as well as for a complete loss of service water. The baseline conditional core damage probability was determined to be 7.06×10^{-3} by changing the initiating event likelihood to 2.258×10^{-2} (failure probability with one pump remaining), while failing Pumps B, C, and D. The current case probability was 1.0, because a loss of service water would have occurred without recovery. However, the licensee argued that late injection was still possible.

The analyst reviewed the licensee's procedures and equipment for providing late injection via the control rod drive hydraulic system using the demineralized water system as a heat sink for the pumps. This method appeared to be viable and calculations supported the determination that this provided a success path for an unrecovered loss of service water. The SPAR provides a 2×10^{-2} failure probability for the control rod drive hydraulic system. Qualitatively including a nominal failure probability for the operator diagnosis and actions required, as well as for the availability/failure potential of the demineralized water system, the analyst agreed with the licensee and Brookhaven National Laboratory (documented in the risk-informed notebook) that a failure probability of 0.1 was appropriate for the function. Therefore, the analyst modified the SPAR to include a 0.9 success probability for Loss of Station Service Water Sequence 15 following successful depressurization. The resulting ΔCDP was 3.27×10^{-2}.

The analyst also assessed the affect of this finding on a postulated fire in Switchgear 1G. The analyst walked down the switchgear rooms and interviewed licensed operators. The analyst identified that, by procedure, a fire in Switchgear 1G would require deenergization of the bus and subsequent manual scram of the plant. Additionally, the analyst noted that no automatic fire suppression existed in the room. Therefore, the analyst used the fire ignition frequency stated in the IPEEE, namely $3.70 \times 10^{-3}/yr$ ($L_{switchgear}$), as the frequency for loss of Switchgear 1G and a transient.

The analyst used the SPAR model to quantify the conditional core damage probabilities for a fire in Switchgear 1G. The baseline CCDP was 1.55×10^{-4} ($CCDP_{base}$) with a failure of Division II service water. The case CCDP was 1.19×10^{-2} ($CCDP_{current}$) using a 0.5 probability of Pump A failing (Probability that Pump C is running). The ΔCDF was calculated as follows:

$$\Delta CDF = L_{switchgear} * (CCDP_{current} - CCDP_{base})$$

$$= 3.70 \times 10^{-3}/yr * (1.19 \times 10^{-2} - 1.55 \times 10^{-4})$$

$$= 4.35 \times 10^{-5}/yr$$

Table 4: Internal Fire Risk				
Fire Areas:	Fire Type	Fire Ignition Frequency	ΔCDP	ΔCDF
Switchgear 1G	Shorts Bus	3.70×10^{-3}/yr	1.17×10^{-2}	4.35×10^{-5}/yr
Service Water Pump Room	One Pump	5.99×10^{-6}/yr	2.34×10^{-4}	1.40×10^{-9}/yr
	Three Pumps	1.47×10^{-4}/yr	3.27×10^{-2}	4.81×10^{-6}/yr
Total ΔCDF for Fires affecting the Service Water System:				4.83×10^{-5}/yr
Exposure Time (59 hrs ÷ 365 days/yr ÷ 24 hrs/day):				6.74×10^{-3} yrs
External Events Change in Core Damage Frequency:				3.26×10^{-7}

<u>Potential Risk Contribution from Large Early Release Frequency (LERF)</u>:

In accordance with Manual Chapter 0609, Appendix A, Attachment 1, step 2.6, “Screening for the Potential Risk Contribution Due to LERF,” the analyst assessed the impact of LERF because the Phase 2 SDP result provided a risk significance estimation of 7.

As documented in a letter from Arthur T. Howell III, Director, Division of Reactor Projects to Randall K. Edington, Vice President-Nuclear and CNO for the Nebraska Public Power District, dated March 31, 2005, the NRC previously evaluated the dominant sequences associated with a loss of service water initiator at Cooper. The conclusion was that, at the Cooper Nuclear Station, no significant LERF sequences are derived from a loss of service water. The postulated core damage sequences take more time than the average to progress to core damage. This would provide additional time to vessel breach and the postulated release. Additionally, the licensee and the states of Nebraska and Missouri have documented that there is a relatively short time estimated to evacuate the close-in population surrounding Cooper Nuclear Station.

LERF is defined in NRC Inspection Manual Chapter 0609, Appendix H, “Containment Integrity Significance Determination Process,” as “the frequency of those accidents leading to significant, unmitigated release from containment in a time frame prior to the effective evacuation of the close-in population such that there is a potential for early health effect.” The NRC has noted that the dominant core damage sequences following a loss of service water at Cooper are long sequences that take greater than 12 hours to proceed to reactor pressure vessel breach. The shortest calculated interval from the time reactor conditions would have met the requirements for entry into a general emergency (requiring the evacuation) until the time of postulated containment rupture was 3.5 hours. The licensee stated that the average evacuation time for Cooper from the declaration of a General Emergency was 62 minutes.

The NRC determined that, based on a 62-minute average evacuation time, effective evacuation of the close-in population could be achieved within 3.5 hours. Therefore, the dominant core damage sequences affected by the subject performance deficiency were not LERF contributors. As such, the NRC's best estimate determination of the change in LERF resulting from the performance deficiency was zero.

VII. References:

NRC Inspection Report 50-298/2005004

Risk-informed Inspection Notebook for Cooper Nuclear Station, Revision 1

Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations"

Manual Chapter 0612, "Power Reactor Inspection Reports"

Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process"

VIII. Participation:

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Analyst: David Loveless
Peer Reviewer: Russ Bywater