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

October 31, 2002

David L. Wilson, Vice President of
Nuclear Energy
Nebraska Public Power District
P.O. Box 98
Brownville, Nebraska 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INSPECTION REPORT 50-298/02-03

Dear Mr. Wilson:

On October 5, 2002, the NRC completed an inspection at your Cooper Nuclear Station. The enclosed report documents the inspection findings which were discussed on October 3, 2002, with Mike Coyle 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. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC has determined that four violations of NRC requirements occurred. Based on the results of this inspection, the NRC has identified issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that violations are associated with these issues. These violations are being treated as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or significance of these NCVs, 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; 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 2.790 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 (PARS) 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 F
Division of Reactor Projects

Docket: 50-298
License: DPR-46

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NRC Inspection Report
50-298/02-03

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-298
License:	DPR 46
Report No.:	50-298/02-03
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	July 7 through October 5, 2002
Inspectors:	S. Schwind, Senior Resident Inspector J. Melfi, Reactor Inspector, Engineering and Maintenance Branch R. Lantz, Senior Emergency Preparedness Specialist P. Elkmann, Emergency Preparedness Specialist
Approved By:	K. Kennedy, Chief, Project Branch F, Division of Reactor Projects

ATTACHMENT: Supplemental Information

SUMMARY OF FINDINGS
Cooper Nuclear Station
NRC Inspection Report 50-298/02-03

IR 05000298/02-03; Nebraska Public Power District; 07/07-10/05/02; Cooper Nuclear Station. Integrated Resident/Regional Report; Permanent Plant Modifications, Access Authorization, Identification & Resolution of Problems.

The inspection was conducted by resident inspectors and Region IV specialists. During the inspection the NRC identified six Green findings, five of which were noncited violations. The significance of each issue is indicated by its color (Green, White, Yellow, or Red) and was determined by the Significance Determination Process (SDP) in Inspection Manual Chapter 0609.

Cornerstone: Initiating Events

- Green. The unplanned loss of power to four effluent radiation monitors during the installation of a service water radiation monitoring system modification was considered to be a self-revealing, Green finding. The modification package required lifting an energized lead to de-energize a portion of the old service water radiation monitoring system; however, due to errors made by design engineering, this step unintentionally de-energized four other effluent radiation monitors which were required to be operable per the Technical Requirements Manual.

  The finding was considered more than minor since the modification package required lifting energized leads in control room panels which could reasonably be viewed as a precursor to a significant event if not adequately controlled. The finding was characterized as having very low safety significance since the loss of the effluent monitors did not result in a release in excess of allowable limits (Section 1R17).

Cornerstone: Mitigating Systems

- Green. The licensee failed to identify and correct degraded spray shields associated with sprinkler heads on Sprinkler System 29 in the cable expansion room which provides fire protection for cable trays containing redundant divisions of safety-related cables. The spray shields were identified as having holes in them which would result in decreasing the effectiveness of the shields. This was a violation of License Condition 2.C.(4). This finding had crosscutting aspects associated with problem identification and resolution since the licensee had multiple opportunities to identify and correct this condition but failed to do so.

  This finding was more than minor since failure of this system during a fire would have adversely impacted the availability, reliability, and capability of systems that respond to an initiating event. The finding was characterized under the significance determination process as having very low safety significance since the alternate shutdown capability was unaffected and due to the low fire ignition frequency for the cable expansion room. Because of the very low safety significance and because the licensee entered the item in their corrective action program as Notification 10190964, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (Section 1R05).

- Green. The licensee failed to take corrective actions for a surveillance test procedure that rendered the high pressure coolant injection system and the reactor core isolation cooling system concurrently inoperable. The procedural error was identified by the licensee in 1998 but no action was taken due to an incorrect conclusion that the procedure did not actually render the high pressure coolant injection system inoperable. When this question was addressed again in 2002, the licensee concluded that the system was, in fact, inoperable. This configuration was allowed by Technical Specifications; however, operators failed to recognize it as an entry condition into a shutdown action statement. No violation of the action statement was identified but the failure to recognize its entry condition was considered a condition adverse to quality. Therefore, this was considered to be a violation of 10 CFR Part 50, Appendix B, Criterion XVI. This finding also had crosscutting aspects associated with problem identification and resolution.

  This finding was characterized under the significance determination process as having very low safety significance because the high pressure coolant injection system could have performed its safety function even though it was considered inoperable per Technical Specifications. The finding was more than minor since the procedural error had an adverse impact on the availability and capability of a mitigating system. Because of the very low safety significance and because the licensee included the item in their corrective action program as Notification 10193745, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (Section 1R22).

- Green. The licensee failed to take corrective actions to prevent clogging of instrument line snubbers which resulted in the inadvertent isolation of the reactor core isolation cooling system on May 14, 2002. This was an apparent violation of 10 CFR Part 50, Appendix B, Criterion XVI. This finding also had crosscutting aspects associated with problem identification and resolution.

  This finding was characterized under the significance determination process as having very low safety significance based on the results of a Phase 3 analysis. The finding was more than minor since it had an adverse impact on the availability, reliability, and capability of a mitigating system. Because of the very low safety significance and because the licensee included the item in their corrective action program as Resolve Condition Report 2002-0895, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (Section 4OA5).

Cornerstone: Physical Protection

- Green. The failure of the security search to detect and control a box of ammunition as it entered the protected area was considered to be a self-revealing, Green, noncited violation of 10 CFR 73.55(d)(3).

  This finding was characterized by the significance determination process as having very low safety significance since there were not more than two similar findings in the past four quarters. It was considered more than minor because it represented a failure to meet the requirements of 10 CFR 73.55(d) and the licensee's security plan. Because of the very low safety significance and because the licensee entered this finding into their corrective action program as Notification 10181426, this violation is being treated as a noncited violation consistent with Section VI.A of the NRC Enforcement Policy (Section 3PP2).

Report Details

The plant was operated at essentially 100 percent power throughout the inspection period.

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

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

The inspectors performed three partial equipment alignment inspections. The inspections verified that the critical portions of the selected systems were correctly aligned per the system operating procedures. The following systems were included in the scope of this inspection:

- Diesel Generator 2 while Diesel Generator 1 was out of service for planned maintenance on August 13. The inspection included portions of the system in the Diesel Generator 2 room.

- Optimum water chemistry system after the system had been started for the first time. This nonsafety-related system generates and stores hydrogen gas; therefore, its operation contributes to overall plant risk. The inspection included portions of the system located in the optimum water chemistry building.

- Residual Heat Removal System A while Residual Heat Removal System B was out of service for heat exchanger cleaning on September 18. The inspection included portions of the system in the control room and reactor building on Elevations 859, 881, 903, and 931.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope

The inspectors performed eight fire zone walkdowns to determine if the licensee was maintaining those areas in accordance with their Fire Hazards Analysis Report. The fire zones were chosen based on their risk significance as described in the Individual Plant Examination of External Events. The walkdowns focused on control of combustible material and ignition sources, operability and material condition of fire detection and suppression systems, and the material condition of passive fire protection features. The following fire zones were inspected:

- Fire Zone 1A - Reactor core isolation cooling (RCIC) pump room
- Fire Zone 2A - Reactor building, Elevation 903, north corridor
- Fire Zone 1E - High pressure coolant injection (HPCI) pump room
- Fire Zone 1F - Suppression pool area

- Fire Zone 9B - Cable expansion room
- Fire Zone 2C - Reactor building, Elevation 903, rail bay
- Fire Zone 2C - Control building, Elevation 903
- Transformer yard south of the reactor building

b. Findings

The inspectors identified a Green, noncited violation of License Condition 2.C.(4) regarding the failure to identify and correct degraded conditions on the automatic fire suppression system in the cable expansion room. The licensee failed to identify and correct deficiencies with sprinkler head spray shields which could have rendered portions of the system inoperable during a fire in this room.

On August 21, 2002, the inspectors conducted a walkdown of the fire protection features in the reactor building, Elevation 903, and observed what were believed to be heat collectors installed above the sprinkler heads for Sprinkler System 35. These sprinklers were located approximately 10 feet below the ceiling along the north corridor of the reactor building. Each heat collector consisted of a 1-square foot section of galvanized metal installed above the sprinkler head; some were not perfectly horizontal, as a heat collector should be for optimum operation. Potential problems with heat collectors on fire protection sprinklers were discussed in NRC Information Notice (IN) 2002-24, dated July 19, 2002. This IN stated that heat collectors used on sprinkler heads located further below the ceiling than allowed by the National Fire Protection Association code may not operate as designed and may actually increase the response time for a fusible link sprinkler head. The inspectors questioned whether the licensee was aware of this information and if Sprinkler System 35 would perform its design function in its current configuration.

The licensee responded that they had received IN 2002-24 and determined it to be applicable at Cooper Nuclear Station. It was entered into their corrective action program as Notification 10182979 on July 31 but no operability determination was performed at that time. The potential operability impact on sprinkler systems at Cooper was not addressed until August 21 and then only as a result of the inspectors' questions. As a result, the licensee declared Sprinkler System 35 inoperable and posted a continuous fire watch as a compensatory measure. The licensee also performed a complete walkdown of all other sprinkler systems in the plant which resulted in an additional six systems being declared inoperable due to similar concerns. Included in these was Sprinkler System 29 in the cable expansion room which provides fire protection for cable trays containing redundant divisions of safety-related cables. Appropriate compensatory measures were established for these additional inoperable systems.

The licensee completed an operability determination which stated that the metal pieces installed above the sprinkler heads on Sprinkler Systems 29 and 35 were unauthorized modifications which had actually been installed as spray shields rather than heat collectors. Spray shields are used when a fusible link sprinkler head is installed inside the spray pattern of another sprinkler to prevent the water spray from affecting the operation of the fusible link. The operability determination demonstrated that the plant's fire safe shutdown capability was not impaired by this issue and subsequently Sprinkler Systems 29 and 35 were declared operable in their current configuration.

On September 3, 2002, the inspectors performed a walkdown of the fire suppression system in the cable expansion room to validate the conclusions in the operability determination. The inspectors observed that several of the metal plates above the sprinkler heads in this area, which were considered spray shields by the operability determination, had holes drilled in them so that water from other sprinkler heads could drip directly onto the fusible links and prevent proper operation. The inspector discussed this with the licensee, which resulted in declaring Sprinkler System 29 inoperable for a second time. Compensatory measures were established for this fire area while the holes in the spray shields were plugged. The licensee also performed additional walkdowns to confirm that this condition did not exist on any other sprinkler system.

The licensee's failure to promptly identify and correct deficiencies on Sprinkler System 29 in the cable expansion room affected the mitigating systems cornerstone since this sprinkler system is used to protect cable trays containing redundant divisions of safety-related cables. This finding was considered more than minor since failure of this system during a fire would have adversely impacted the availability, reliability, and capability of systems that respond to an initiating event. Inspection Manual Chapter (MC) 0609, "Significance Determination Process," was used to assess the safety significance of this finding. Phase 1 of the significance determination process concluded that the finding was potentially risk significant since it affected a system designed to mitigate an external event (fire) and failure of this system would degrade two or more trains of a multitrain safety system or function. Therefore, a Phase 2 analysis using MC 0609, Appendix F, was required.

The following assumptions were used during the Phase 2 analysis:

- The condition existed for more than 30 days.

- An automatic fire detection and a fixed suppression system was relied upon to minimize damage to redundant divisions of equipment in the cable expansion room. No rated fire barrier or sufficient horizontal separation existed between the redundant divisions.

- Sprinkler System 29 was assumed to be highly degraded. This was a conservative assumption used to establish a bounding case.

- Manual firefighting effectiveness (fire brigade) was assumed to be at its normal operating state.

- According to Cooper Nuclear Station's Individual Plant Examination of External Events, the ignition frequency for a fire in the cable expansion room is 6.89E-4/year.

- A fire in the cable expansion room would adversely affect the ability to reach and maintain safe shutdown conditions from the control room, but that ability would remain unaffected from the alternate shutdown panel in the reactor building.

This set of assumptions resulted in a fire mitigation frequency of -5 to -6. Based on this frequency and the fact that mitigation capability remained unaffected from the alternate shutdown panel, this finding was determined to have very low safety significance (Green).

This finding also had crosscutting aspects associated with problem identification and resolution. This assessment was based on the fact that the licensee had multiple opportunities to identify and correct the deficiencies with Sprinkler System 29 yet failed to do so. A walkdown of the system should have been, but was not, performed based on receipt of IN 2002-24; when the walkdown was performed, in response to the inspectors' questions, the licensee failed to identify the deficiencies in the spray shields. This crosscutting issue is an additional example of a substantive crosscutting issue most recently described in Cooper Nuclear Station's Midcycle Performance Review letter dated August 26, 2002.

License Condition 2.C.(4) of Cooper Nuclear Station's operating license (License DPR-46) states that the licensee is required to implement the administrative controls identified in Section 6 of the NRC's Fire Protection Safety Evaluation, dated May 23, 1979, for the facility. Section 6 of this safety evaluation requires the implementation of quality assurance provisions for the fire protection program. Section XIII-10.2 of the Updated Final Safety Analysis Report states that the fire protection program will comply with Branch Technical Position APCSB 9.5-1, Appendix A, which requires that conditions adverse to fire protection, such as deficiencies, deviations, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to promptly identify and correct deficiencies with the spray shields installed in Sprinkler System 29 despite multiple opportunities to do so. This violation of License Condition 2.C.(4) is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (50-298/0203-01). The licensee entered this finding into their corrective action program as Notification 10190964 and completed immediate corrective actions to plug the holes in the spray shields.

1R06 Flood Protection Measures (71114.06)

a. Inspection Scope

The inspectors performed an annual inspection of external flood protection features. The inspection included a review of the Update Final Safety Analysis Report to determine if any changes had been made to the plant which affected the assumptions in the flood protection analysis. The inspectors also reviewed Emergency Procedure 5.1, "Flood," Revision 1, and Maintenance Procedure 7.0.11, "Flood Control Barriers," Revision 1, to verify that procedures were adequate to address potential seasonal flooding. The inspectors conducted a walkdown to verify that the materials required by Maintenance Procedure 7.0.11 for establishing emergency flood barriers were in their designated storage location and were in serviceable condition.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

Introduction

The inspectors conducted a biennial review to verify: (1) that any potential heat exchanger deficiencies, which could mask degraded performance, were identified; (2) that any potential common cause heat sink performance problems that had the potential to increase risk at the facility were identified; and (3) that the licensee had adequately identified and resolved heat sink performance problems that could result in initiating events or effect multiple heat exchangers in mitigating systems and, thereby, increase risk. The inspectors used the plant risk assessment to select the three components listed below for review:

Diesel generator jacket water coolers
Diesel generator lube oil coolers
Residual heat removal system heat exchangers

The inspectors also walked through the intake structure by the service water pumps to assess material condition.

.1 Performance of Testing, Maintenance, and Inspection Activities - Biennial Review

a. Inspection Scope

The inspectors reviewed the inspection, maintenance, and test methodologies for the selected components.

The inspectors considered the extrapolation of test conditions to design conditions, the use of appropriate test instrumentation, and the appropriate consideration of instrument inaccuracies. Additionally, the inspectors considered whether the licensee appropriately trended these inspection and test results, assessed the causes of the trends, and took necessary actions for any notable trends.

b. Findings

No findings of significance were identified.

.2 Verification of Conditions and Operations Consistent with Design-Bases - Biennial Review

a. Inspection Scope

For the selected components, the inspectors considered whether the licensee-established component material condition, operation, and test criteria remained consistent with the design assumptions. Specifically, the inspectors reviewed the applicable test calculations to ensure that the thermal performance test acceptance criteria for the selected components were being applied consistently throughout the calculations. The inspectors also determined that the appropriate acceptance values for fouling and tube plugging for heat exchangers and room coolers remained consistent with the values used in the design-basis calculations. Finally, the inspectors considered the parameters measured during the thermal performance and flow balance tests for the selected systems to be consistent with those assumed in the design-bases.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors examined the corrective action program for significant problems with the selected components over the past 2 years. The inspectors reviewed a sample of five condition reports, which are identified in the attachment to this report.

The inspectors used Inspection Procedure 71152, "Identification and Resolution of Problems," as additional guidance for reviewing these issues and verifying that the licensee took appropriate actions to prevent recurrence of the identified problems.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12Q)

a. Inspection Scope

The inspectors reviewed several equipment performance issues to assess the licensee implementation of their maintenance rule program. The inspectors verified that the systems, structures, and components that experienced these problems were properly included in the scope of the licensee's maintenance rule program, the appropriate performance criteria were established, and in the case of systems, structures, and components monitored under paragraph a(1) of the rule, the established goals and corrective actions were appropriate. Maintenance rule implementation was determined to be adequate if it met the requirements outlined in 10 CFR 50.65 and Administrative Procedure 0.27, "Maintenance Rule Program," Revision 11. The inspectors reviewed the following three equipment performance problems:

- Service Water Zurn Strainer A clogging with river debris on July 15
- Failure of HPCI turbine drain Valve HPCI-SOV-SSV64 on June 24 due to foreign material lodged in the valve

- Failure of the reactor building airlock door interlocks on July 18

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed five risk assessments for planned or emergent maintenance activities to determine if the licensee met the requirements of 10 CFR 50.65(a)(4) for assessing and managing any increase in risk from these activities. Evaluations for the following maintenance activities were included in the scope of this inspection:

- Bypassing and cleaning of the service water pump discharge strainers on July 15
- Replacement of the essential station service transformer potential transformers on July 30
- Draining, cleaning, and inspection of Residual Heat Removal Heat Exchanger A on September 10
- Replacement of Control Rod Drive Hydraulic Accumulator 18-19 on September 13
- Performance of Surveillance Procedure 6.1CS702, "CS Loop A Pump Time Delay Channel Functional Test (Div 1)," Revision 1, on September 13, which requires declaring Diesel Generator 1 inoperable

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed four operability determinations regarding mitigating system capabilities to ensure that the licensee properly justified operability and that the component or system remained available such that no unrecognized increase in risk occurred. These reviews considered the technical adequacy of the licensee's evaluation and verified that the licensee considered other degraded conditions and their impact on compensatory measures for the condition being evaluated. The inspectors referenced the Updated Final Safety Analysis Report, Technical Specifications, and associated system Design Criteria Documents to determine if operability was justified. The inspectors reviewed the following equipment conditions and associated operability evaluations:

- Unexpected cycling of Relay 27X-1GB during undervoltage relay testing on safety-related 4160 volt Bus 1G on July 5 (Notification 10176269)

- Partial blockage of the A and B service water Zurn strainer on July 15 (Notification 10179059)

- Crack indications detected on core spray piping Weld P4B (Notification 10183261)

- Improper installation of the outboard generator bearing oil slinger rings on Diesel Generator 2 (Notification 10184395)

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The inspectors reviewed Plant Modification CED 6005412, “Service Water Radiation Monitor System Upgrade,” and the condition reports that documented an unplanned loss of power to several effluent radiation monitors that occurred during implementation of the modification.

b. Findings

The unplanned loss of power to four effluent radiation monitors during the installation of a new service water radiation monitoring system was considered to be a self-revealing, Green finding. Steps in the modification package to install the new system were intended to de-energize a portion of the old service water radiation monitoring system; however, the steps unintentionally de-energized four other effluent radiation monitors which were required to be operable per the Technical Requirements Manual.

On July 25, 2002, work was in process to install a control room recorder for the new service water radiation monitoring system. The modification package specified that an energized lead on Terminal 284 of Terminal Block 25 in control room Cabinet VBD-G be lifted to de-energize various equipment associated with the service water radiation monitoring system. When this lead was lifted, multiple radiation monitor recorders and remote indicators were unexpectedly de-energized. As a result, the following instruments were declared inoperable per the Technical Requirements Manual:

- RMV-RM-40 Reactor building radioactive effluent monitor

- RMV-RM-10 Multipurpose facility radioactive effluent monitor

- RMV-RM-30A Radioactive waste/augmented radioactive waste normal range radioactive effluent monitor

- RMV-RM-30B Radioactive Waste/Augmented Radioactive Waste High Range radioactive effluent monitor

Once it was determined that the lead in question had caused the loss of power to these effluent radiation monitors, the lead was re-landed and power was restored in approximately 10 minutes.

The licensee entered this condition into their corrective action program as Resolve Condition Report (RCR) 2002-1576 and performed an apparent cause determination, which concluded that the design engineer had not thoroughly researched the wiring diagrams for this particular cabinet in the control room which led to the error in the modification package. In addition, there was a failure in the licensee's quality control of engineering products since the package received an independent design review by another more experienced engineer, which failed to detect and correct the error prior to implementation. The external, as-built wiring diagrams used in development of the modification package were generic in nature and did not reflect the actual configuration of terminal blocks and electrical leads in Cabinet VBD-G. This set of diagrams only showed an electrically equivalent representation of Terminal Block 25 and did not clearly indicate that the lead on Terminal 284 supplied power to the aforementioned effluent monitors. A second set of internal, as-built wiring diagrams should have been referenced which would have shown that this lead supplied power to the effluent monitors and not just the service water monitor.

This finding was considered more than minor since it could reasonably be viewed as a precursor to a more significant event. The failure of design engineering to produce a quality design modification package which involves lifting energized leads in a control room panel could lead to a more significant event, such as rendering safety systems inoperable or resulting in a plant trip. This particular event affected the public radiation safety cornerstone since power was lost to effluent radiation monitors. Inspection Manual Chapter 609, "Significance Determination Process," Appendix D, was used to assess the safety significance of this finding. This finding did not involve the control of radioactive material; however, it did affect the licensee's radioactive effluent release program. The licensee's ability to assess dose was not impaired since they immediately recognized the affect of the loss of power to the effluent monitors and the need to take compensatory grab samples. In addition, power was restored within 10 minutes. No offsite dose limits were exceeded during this 10-minute period; therefore, Phase 1 of the significance determination process assessed the finding as having very low safety significance (Green).

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed or observed selected postmaintenance tests to verify that the procedures adequately tested the safety functions that were affected by maintenance activities on the associated systems. The inspectors also verified that the acceptance criteria were consistent with information in the applicable licensing basis and design basis documents and that the procedures were properly reviewed and approved.

Postmaintenance tests for the following four maintenance activities were included in the scope of this inspection:

- Replacement of the three potential transformers associated with the essential station service transformer on July 30 (Work Order 4255763)
- Cleaning and inspection of Residual Heat Removal Heat Exchanger A on September 10 (Work Order 4258590)
- Replacement of Control Rod Drive Hydraulic Accumulator 18-19 on September 13 (Work Order 4243836)
- Adjustments made to the reactor core isolation cooling pump turbine overspeed trip mechanism linkage on September 30 (Work Order 4270735)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed or reviewed the following six surveillance tests to ensure that the systems were capable of performing their safety function and to assess their operational readiness. Specifically, the inspectors verified that the following surveillance tests met Technical Specifications, the Updated Final Safety Analysis report, and licensee procedural requirements:

- 6HPCI302, “HPCI Suppression Chamber and ECST Water Level Channel Calibration,” Revision 6, performed on May 22
- 6.1ARI301, “ARI/ATWS/RPT Low-Low and PCIS Low-Low-Low Reactor Water Level Channel Calibration Test (Div I),” Revision 5, performed on July 19
- 6DWLD201, “Drywell Sump Accumulator Check Valve Exercise Test,” Revision 5, performed on July 24
- 6.1CS101, “Core Spray Test mode Surveillance Operation (IST) (Div I),” Revision 5, performed on August 14
- 15RR302, “Core Flow Determination,” Revision 7, performed on August 22
- 6CRD301, “Withdrawn Control Rod Operability IST Test,” Revision 13, performed on September 13

b. Findings

The inspectors identified a Green, noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, regarding the failure to correct procedural deficiencies. The licensee failed to correct deficiencies in a surveillance test procedure which rendered the HPCI system and the RCIC system inoperable concurrently.

During performance of Surveillance Procedure 6HPCI302, “HPCI Suppression Chamber and ECST Water Level Channel Calibration,” Revision 6, on May 2, 2002, control room operators recognized that steps in the procedure would isolate both the suppression pool and emergency condensate storage tank suction paths to HPCI and RCIC at the same time, rendering both systems inoperable. This configuration would require entry into Technical Specification Action Statement 3.5.1.G.1 which requires a plant shutdown within 12 hours. This procedure is performed every 92 days; however, on previous occasions, operators did not recognize the entry conditions for this action statement. Realizing that this was an undesirable plant configuration, operators suspended the test on May 2 and restored both systems to an operable configuration. This procedural inadequacy was documented in the licensee’s corrective action program as Notification 10158840. As a result, the procedure was revised so that HPCI and RCIC would not be rendered inoperable at the same time. The licensee also reviewed operator logs and surveillance test records and determined that the 12-hour completion time of the action statement had not been exceeded at any time while performing this procedure in the past; therefore, no violation of Technical Specifications was identified.

The inspectors reviewed Notification 10158840 and the corrective actions as well as performed a search of past corrective action documents for similar occurrences. It was discovered that a condition report (CR 98-0500) had been written in 1998 which described the same concern with Surveillance Procedure 6HPCI302. The condition report was closed with no action taken based on the conclusion that HPCI had not been rendered inoperable by the procedure since the suction valve from the emergency condensate storage tank (HPCI-MOV-MO17) would automatically stroke open if an automatic initiation signal was received. However, Section VI-6 of the Updated Final Safety Analysis Report describes HPCI as being normally aligned to the emergency condensate storage tank, and the loss of coolant accident analysis for Cooper Nuclear Station states that HPCI must automatically start and deliver a flow rate of 3825 gallons-per-minute to the core within 60 seconds of a loss-of-coolant accident. The inservice testing program only required HPCI-MOV-MO17 to stroke full open within 78 seconds and no analysis existed to support the conclusion that the HPCI system could provide the required flow within 60 seconds while this valve was stroking open. Based on this, the inspectors concluded that HPCI was rendered inoperable per Technical Specifications and operators should have recognized the entry conditions for the shutdown action statement.

The licensee’s failure to recognize that Surveillance Procedure 6HPCI302 rendered HPCI and RCIC inoperable at the same time affected the mitigating systems cornerstone. This finding was greater than minor since the test procedure had an adverse impact on the availability and capability of both systems which are relied upon to mitigate the consequences of an accident. Inspection Manual Chapter 609, "Significance Determination Process," was used to assess the safety significance of this finding. It was assumed that this condition existed for a maximum of 5.5 hours each quarter while the test was performed and that HPCI-MOV-MO17, which is a 16-inch motor-operated gate valve, would allow full flow prior to fully opening; therefore, the finding did not represent an actual loss of safety function. This finding did not involve an external initiating event; therefore, Phase 1 of the significance determination process assessed the finding as having very low safety significance (Green).

This finding also had crosscutting aspects associated with problem identification and resolution. This assessment was based on the fact that the licensee had previously identified the procedure deficiencies in Surveillance Procedure 6HPCI302 but failed to correct them based on an incorrect conclusion that the HPCI system had not been rendered inoperable by the procedure. This crosscutting issue is an additional example of a substantive crosscutting issue most recently described in Cooper Nuclear Station's Midcycle Performance Review letter dated August 26, 2002.

Appendix B, Criterion XVI, of 10 CFR Part 50, states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Failure to recognize that safety equipment is inoperable and enter the appropriate Technical Specification action statement is a condition adverse to quality. In 1998, the licensee incorrectly concluded that Surveillance Procedure 6HPCI302 did not render HPCI inoperable so no corrective actions were taken. This violation of 10 CFR Part 50, Appendix B, Criterion XVI, is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (50-298/0203-02). The licensee entered this finding into their corrective action program as Notification 10193745 and completed immediate actions to correct the procedural deficiencies.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the temporary plant modification which installed a temporary temperature probe in the service water intake bays to ensure that the modification did not adversely affect system operability or design requirements specified in the Updated Final Safety Analysis Report and Technical Specifications. This review also included the testing requirements after installation and removal of the temporary modification as well as how configuration control of the service water intake structure would be maintained.

b. Findings

No findings of significance were identified.

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2002 Biennial Emergency Preparedness Exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario included reactor protection system problems, a main steam break inside containment, a loss-of-coolant accident, fuel damage, and an unfiltered radiological release to demonstrate the licensee's capabilities to implement the emergency plan.

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

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

The inspectors also assessed personnel recognition of abnormal plant conditions, the transfer of emergency responsibilities between facilities, communications, protection of emergency workers, emergency repair capabilities, and the overall implementation of the emergency plan to verify compliance with the requirements of 10 CFR 50.47(b), 10 CFR 50.54(q), and Appendix E to 10 CFR Part 50.

The inspectors attended the postexercise critiques in each of the above emergency response facilities to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended the formal presentation of critique items to plant management.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed Revision 39 to the Cooper Nuclear Station Emergency Plan and Revisions 29 and 29C1 to Procedure 5.7.1, "Emergency Classification," against previous revisions and 10 CFR 50.54(q) to determine if the revisions decreased the effectiveness of the emergency plan.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On July 31, 2002, the inspectors observed the licensee perform an emergency preparedness drill. Observations were conducted in the emergency operations facility.

During the drill, the inspectors assessed the licensee's performance related to classification, notification, and protective action recommendations. Following the drill, the inspectors reviewed the licensee's critique to determine if issues were appropriately identified and documented. The following documents were reviewed during this inspection:

- Emergency Plan for Cooper Nuclear Station
- Emergency Plan Implementing Procedures for Cooper Nuclear Station
- Cooper Nuclear Station Emergency Preparedness Drill Scenario for July 31, 2002

b. Findings

No findings of significance were identified.

3. SAFEGUARDS
Cornerstone: Physical Protection

3PP1 Response to Contingency Events (71130.03)

The Office of Homeland Security developed a Homeland Security Advisory System (HSAS) to disseminate information regarding the risk of terrorist attacks. The HSAS implemented five color-coded threat conditions with a description of corresponding actions at each level. NRC Regulatory Information Summary 2002-12a, dated August 19, 2002, "NRC Threat Advisory and Protective Measures System," discusses the HSAS and provides additional information on protective measures to licensees.

a. Inspection Scope

On September 10, 2002, the NRC issued a Safeguards Advisory to reactor licensees to implement the protective measures described in Regulatory Information Summary 2002-12a in response to the Federal government declaration of threat level "orange." Subsequently, on September 24, 2002, the Office of Homeland Security downgraded the national security threat condition to "yellow" with a corresponding reduction in the risk of a terrorist threat.

The inspector interviewed licensee personnel and security staff, observed the conduct of security operations, and assessed licensee implementation of the threat level "orange" protective measures. Inspection results were communicated to the Region IV and Headquarters security staff for further evaluation.

b. Findings

No findings of significance were identified.

3PP2 Access Control (71130.02)

a. Inspection Scope

The inspectors reviewed the root cause and corrective actions associated with the failure to detect prohibited contraband from entering the protected area. Notifications and the licensee's search procedures were reviewed and interviews were conducted with several members of the security department to determine the significance of this event.

b. Findings

The failure of the security search to detect and control a box of ammunition as it entered the protected area was considered to be a self-revealing, Green, noncited violation of 10 CFR 73.55(d)(3).

On July 25, 2002, warehouse personnel delivered a package containing 150 rounds of ammunition to a security employee's desk. Security Procedure 2.7, "Material Entry/Exit," Revision 9.3, defines ammunition as prohibited contraband inside the protected area unless it is authorized and controlled by security personnel. Other security personnel in the area questioned why the ammunition was delivered in this manner, and it was discovered that it had arrived onsite the previous day and was processed into the protected area along with other routine deliveries on July 24, 2002. Routine deliveries are x-rayed and searched prior to entering the protected area; however, the ammunition was not detected during this search and security personnel did not take custody of it once it entered the protected area. Security personnel immediately took custody of the ammunition and began an investigation into the cause of this event.

The licensee entered this condition into their corrective action program as Notification 10181426. The apparent cause of this issue was a failure to implement the search requirements of Security Procedure 2.7. The licensee recalled the archived image from the x-ray machine used to search this package, and the ammunition appeared to be a solid, indistinguishable mass. Security Procedure 2.7, Section 6.3.2.1, requires a physical search of material if the x-ray machine does not provide a clear picture of the contents or an object looks suspicious. This search was not performed.

This finding affected the physical protection cornerstone and was considered more than minor because it represented a failure to meet the requirements of 10 CFR 73.55(d) and the licensee's security plan. The finding also represented a failure of the licensee's access control system which is a key attribute of the physical protection cornerstone. Inspection Manual Chapter 609, Appendix E, was used to assess the safety significance of this finding. The finding represented a vulnerability in the licensee's access control program, but no malevolent act was involved. There were two previous failures of the access control program to detect contraband as it entered the protected area within the past four quarters; however, only one of these was considered a similar finding since corrective action for it should have prevented this most recent finding. This finding was determined to be of very low safety significance (Green).

Paragraph (d)(3) of 10 CFR 73.55 requires that all packages and materials for delivery into the protected area be searched for devices such as firearms, explosives, and incendiary devices prior to admittance into the protected area. The failure to conduct an adequate search of material entering the protected area on July 24, 2002, was a violation of 10 CFR 73.55(d)(3) and is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (50-298/0203-03). The licensee entered this finding into their corrective action program as Notification 10181426 and completed immediate corrective actions by taking custody of the ammunition and reinforcing the requirements of Security Procedure 2.7 with personnel conducting material searches.

Other Activities

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

.1 Initiating Events and Barrier Integrity Performance Indicators

a. Inspection Scope

The inspectors verified the accuracy of reported data for the following six NRC performance indicators:

- Unplanned scrams
- Scrams with loss of normal heat removal
- Unplanned power changes
- Emergency ac power systems unavailabilty
- Heat removal system unavailability
- Residual heat removal systems unavailabilty

b. Findings

No findings of significance were identified.

.2 Drill and Exercise Performance

a. Inspection Scope

The inspectors verified the licensee's reported results for the drill and exercise performance indicator by reviewing a 100 percent sample of records for exercises, actual declared emergencies, drills, and simulator training scenarios conducted from the fourth calendar quarter 2001 through the second calendar quarter 2002 to verify the accuracy of the reported performance indicator data. The inspectors evaluated licensee performance indicator collection and reporting practices against the standards of Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

.3 Emergency Response Organization Drill Participation

a. Inspection Scope

The inspectors verified the licensee's reported results for the emergency response organization drill participation performance indicator from the fourth calendar quarter 2001 through the second calendar quarter 2002 by reviewing drill participation attendance records for a sample of eight key emergency responders. The inspectors evaluated licensee performance indicator collection and reporting practices against the standards of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

.4 Alert and Notification System Reliability

a. Inspection Scope

The inspectors verified the licensee's reported results for the alert and notification system reliability performance indicator by reviewing a 100 percent sample of offsite siren test results performed from the fourth calendar quarter 2001 through the second calendar quarter 2002 to verify the accuracy of the reported performance indicator data. The inspectors evaluated licensee performance indicator collection and reporting practices against the standards of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed aspects of problem identification and resolution regarding degraded conditions on fire protection systems and instrument line snubbers as well as surveillance procedure deficiencies.

b. Findings

Sections 1R05, 1R22, and 4OA5 of this report document findings which had crosscutting aspects associated with problem identification and resolution.

4OA5 Other Activities

.1 Closure of Apparent Violation 50-298/0208-01, "Failure to take corrective actions for instrument line snubber clogging."

NRC Inspection Report 50-298/02-08 detailed a violation of 10 CFR Part 50, Appendix B, Criterion XVI, regarding the failure to take corrective actions for clogged instrument lines which led to a failure of the reactor core isolation cooling system on May 14, 2002.

The inspectors determined that the licensee had failed to complete corrective actions identified through the review of Information Notice 92-33. This failure led directly to the isolation of the RCIC system. Therefore, the finding was considered to be a licensee performance issue which affected the mitigating systems cornerstone. The inspectors also determined that the finding represented an actual loss of safety function of the RCIC system. Therefore, the finding was greater than minor and the Phase 1 screening identified the necessity for a Phase 2 analysis. As discussed in NRC Inspection Report 50-298/02-08, the inspectors initially determined that the finding was of greater than very low safety significance with the dominant sequence being high pressure injection during a loss of service water event.

As a result, a senior reactor analyst was requested to conduct a Phase 3 analysis in accordance with Manual Chapter 0609, Appendix A. The assumptions used in the Phase 3 analysis varied from the initial assumptions used by the inspectors due to additional information provided by the licensee during the analysis. These assumptions were verified by the inspectors to ensure a current factual basis for all data used in the analysis.

The Standardized Plant Analysis Risk (SPAR) model simulation of the event used during the Phase 3 determination was based on the following assumptions:

- The corrosion products that caused the restriction came from the main steam lines and required a motive force to accumulate. This motive force was assumed to be a complete plant cooldown.

- The last complete cooldown of Cooper Nuclear Station had been on January 8, 2002. Therefore, the exposure time for this condition was 155 days.

- The likelihood of corrosion products restricting the snubber was random in nature. Therefore, any 20 psi change in steam pressure was equally likely to cause an isolation throughout the exposure period.

- There were 55 such 20 psi changes during the exposure period (one reactor cooldown from 940 psi, five downpowers, and three surge pressure changes during surveillance testing).

- The steam line isolation seen on May 14, 2002, was caused by the licensee performance issue and, as such, was not part of the original baseline RCIC failure rate.

- No mechanism other than snubber contamination contributed to the steam line isolation.

The SPAR 3i model was modified to include three additional basic events designed to address the finding. All three events were set to FALSE in the baseline model, assuming that this failure method was not part of the baseline failure of the RCIC system. The following basic events were added:

1. <u>RCIC snubber clogs</u>

   This event represented the snubber restriction seen on May 14, 2002, that caused a group isolation of the RCIC steam supply. Based on the assumptions, the event was set to 1.8E-2 (one failure in 55). This was the exact failure rate seen for the snubber. However, this rate was believed to be high because other snubbers with similar conditions also saw pressure changes and did not fail in a similar manner.

2. <u>RCIC snubber fails to clear after clogging</u>

   This event represented a hypothetical condition where the snubber clogged in a manner that did not permit equalization between the sensing line and system pressure. In this case, the isolation would not reset. Therefore, it was assumed that this failure was unrecoverable. This condition has not been observed. During the event on May 14, 2002, the conditions causing the isolation cleared in 9 seconds. Historical issues with the snubbers, discussed in Information Notice 92-33, also involved flow restrictions as opposed to hard blockages. This event was set to 0.1 as a screening value. The actual value was believed to be considerably lower.

3. <u>Operator fails to reset and restart RCIC following isolation</u>

   The analyst used the SPAR Human Reliability Analysis worksheets to estimate the probability that the operator would fail to recognize that RCIC was available and take action to inject the system. Under accident conditions, operators would have had indication of a half isolation with RCIC running. With or without sending a nonlicensed operator to look for a steam break, the operators would be procedurally driven to attempt resetting the isolation and reestablishing RCIC injection. The probability of this was determined to be between 1E-2 and 1E-3, using the worksheet. A probability of 1E-2 was used.

Logically, these basic events were combined to model the failure of the system. Failure of the system required the RCIC snubber to clog and either the snubber fail to clear or the operator fail to reset the isolation. The model was then run to obtain the following results:

Baseline SPAR CDF = 3.12E-5/yr
SPAR ICCDP point estimate = 1.53E-7/yr
SPAR ICCDP Range = 2.30E-8 - 2.76E-7/yr

A sensitivity study was performed on these results by manipulating each of the three new basic events by an order of magnitude in both directions. All results were below the 1E-6 threshold with two exceptions. The first exception occurred when setting the total blockage of the snubber to 1.0. This number was known to be incorrect, because the event is hypothetical and has never occurred. The second case occurred when setting the initial clogging of the snubber to 0.18. This was considered to be extremely high. The snubber specific data provided a point estimate of 0.018. Other snubbers have never failed in this manner. Additionally, the results from both analyses were very low in the white band (1.6E-6 and 1.5E-6, respectively). Therefore, it was determined that the point estimates were acceptable screening values and that the finding was of very low risk significance (Green).

This finding also had crosscutting aspects associated with problem identification and resolution. This assessment was based on the fact that the licensee had previously identified potential problems with instrument line snubber clogging based on a review of IN 92-33 but failed to enter this issue into their corrective action program and develop long-term corrective actions to prevent this from occurring. This crosscutting issue is an additional example of a substantive crosscutting issue most recently described in Cooper Nuclear Station's Midcycle Performance Review letter dated August 26, 2002.

Appendix B, Criterion XVI, of 10 CFR Part 50 states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. The failure to complete corrective actions identified through the review of IN 92-33 led to the isolation of the RCIC system which was considered a condition adverse to quality. This violation of 10 CFR Part 50, Appendix B, Criterion XVI, is being treated as a noncited violation, consistent with Section VI.A of the NRC Enforcement Policy (50-298/0203-04). The licensee entered this finding into their corrective action program as RCR 2002-0895 and completed immediate corrective actions to flush all safety related instrument line snubbers.

4OA6 Meetings, Including Exit

The results of the emergency preparedness inspections were discussed with the licensee on August 29, 2002. The results of the heat sink performance inspection were presented to the licensee on September 13, 2002. The results of the resident inspector activities were discussed with Mr. D. Wilson, Vice President-Nuclear, and other staff personnel on October 3, 2002.

During all meetings, licensee management acknowledged the inspection findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. The inspectors were informed that none of the material examined during the inspection should be considered proprietary.

Supplemental Information

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Bednar, Emergency Preparedness Training Coordinator
S. Bray, Quality Assurance Assessment Supervisor
P. Carlock, Security Operations Supervisor
G. Casto, Manager, Emergency Preparedness
D. Cook, Senior Manager, Emergency Preparedness
M. T. Coyle, Site Vice President
R. Fischer, Emergency Preparedness Drill Coordinator
J. Flaherty, Site Regulatory Liaison
P. Fleming, Risk and Regulatory Affairs Manager
T. Francis, Radiological Operations
S. Freborg, Heat Exchanger Program Engineer
J. Fox, Outage Manager
R. Gardner, Operations Manager
M. Gillan, Assistant to Plant Manager
M. Hammer, Senior Manager of Engineering
T. Hottovy, Assistant PED Manager
J. Hutton, Plant Manager
J. Kelsay, Emergency Preparedness Coordinator
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D. Kunsemiller, Regulatory Affairs Manager
W. Macecevic, Work Control Manager
D. Meyers, Senior Manager, Site Support
D. Pease, Assistant Operations Manager
J. Ranalli, Senior Engineering Manager
J. Sausbury, ESD Manager
S. Rezab, Emergency Preparedness On-Site Coordinator
V. Roppel, Assistant Senior Engineering Manager
T. Stevens, Mechanical Engineering Supervisor
M. Tackett, Operations Supervisor
D. VanDerKamp, Licensing Engineer
D. Vorpaul, SW System Engineer
D. Wilson, Vice President, Nuclear
D. Weyer, ESD

NRC:

M. Hay, Resident Inspector
B. Baca, Health Physicist

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

50-298/0203-01	NCV	failure to promptly identify degraded conditions on a fire suppression system
50-298/0203-02	NCV	failure to correct a procedure deficiency which affected the operability of the high pressure coolant injection system
50-298/0203-03	NCV	failure to detect prohibited contraband during a security search prior to the material entering the protected area
50-298/0203-04	NCV	failure to take corrective actions to prevent instrument line snubber clogging which caused a failure of the reactor core isolation cooling system

Closed

50-298/0208-01	APV	failure to take corrective actions for instrument line snubber clogging

Discussed

FIN		Inadequate modification package which inadvertently de-energized control room equipment

LIST OF ACRONYMS AND INITIALISMS USED

APV	apparent violation
CFR	Code of Federal Regulations
HPCI	high pressure coolant injection
HSAS	Homeland Security Advisory System
NCV	noncited violation
NEI	Nuclear Energy Institute
RCIC	reactor core isolation cooling
RCR	resolve condition report
SPAR	Standardized Plant Analysis Risk

LIST OF DOCUMENTS REVIEWED

Notifications identified during inspection:

10192812, 10192854, 10193275

Corrective Action Documents Reviewed:

Notifications 10146269, 10189149,
SAP Cap Order Number 4202447;RCR 2001-1019
SAP Cap Order Number 4254726;RCR 2002-1326
PIR 4-13685

Work Order Numbers:

WO 4184935	WO 4188464	WO 4188467	WO 4184934
WO 4188367	WO 4258590	PM 06704	

Calculations:

NEDC 93-184	Verification of Senior Engineering calculation on the Thermal Performance of the RHR Heat Exchanger	9/13/01
NEDC 91-239	DGLO/DGJW/DG Intercooler Heat Exchanger Evaluation	12/3/01
NEDC 01-027	RHR Heat Exchanger Thermal Performance Testing Stability Evaluation	4/16/02

Drawing	**Title**	**Revision**
2036, sh. 1	Flow Diagram, Reactor Building, Service Water System	N76
2040, sh. 1	Flow Diagram, Residual Heat Removal Sys Loop ‘B’	N76
2040, sh. 2	Flow Diagram, Residual Heat Removal Sys Loop ‘B’	N10
2077	Flow Diagram, Diesel Gen. Bldg. Service Water, Starting Air, Fuel Oil Sump System & Room Drains	N48

Vendor Drawing	Title	Revision
Sweco —82701	TS Drilling Template & Baffle Plates	0
Sweco —82703	Channel Details	0
Sweco —82704	Shell Details	N01
American Standard 43M1314A19	1314 CP Exchanger	1
American Standard 43M1512A32	1512 CP Exchanger	1
KSV-47-8	Cooling Water Schematic	N20
Sweco —82317	Residual Hear Removal Heat Exchanger	N01

Miscellaneous Documents

NPPD Letter CNSS907024, “Response to Generic Letter 89-13,” 1/29/1990

Procedure 6.SW.102, “Service Water System Post-LOCA flow Verification,” Revision 11, performed on 12/18/01

Heat exchanger Specification sheet, RHR Heat Exchanger, 10/6/93

Heat exchanger Specification sheet, DG Jacket Water cooler, model 1314 CP, 2/27/70

Heat exchanger Specification sheet, DG Lube Oil cooler, model 1512 CP, 2/27/70

Master Lee Energy Services Inspection Summary, November 2001,
Section 2, “A” Residual Heat Removal Exchanger
Section 3, “B” Residual Heat Removal Exchanger
Section 4, # 2 Diesel Generator Jacket Water Cooler,
Section 5, # 2 Diesel Generator Lube Oil Cooler

Master Lee Energy Services Eddy Current Examination for Nebraska Public Power District Diesel Generator Jacket Water and Lower Oil Cooler Heat Exchanger, March 2002

ADDITIONAL DOCUMENTS REVIEWED

N/A	Cooper Station Emergency Plan	Revision 39

Emergency Plan Implementing Procedures:

5.7.1	Emergency Classification	29, 29C1
5.7.2	Shift Supervisor EPIP	17
5.7.6	Notification	36
5.7.7	Activation of the Technical Support Center	28
5.7.8	Activation of the Operations Support Center (OSC)	22
5.7.9	Activation of the Emergency Operation Facility	23
5.7.12	Emergency Radiation Exposure Control	14
5.7.14	Stable Iodine Thyroid Blocking (KI)	11
5.7.15	OSC Team Dispatch	15
5.7.17	Dose Assessment	28
5.7.20	Protective Action Recommendations	15
5.7.21	Maintaining Emergency Preparedness, Emergency Exercises, Drills, Tests, and Evaluations	24