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

October 30, 2003

Clay C. Warren, Vice President of
Nuclear Energy
Nebraska Public Power District
P.O. Box 98
Brownville, Nebraska 68321

SUBJECT: COOPER NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000298/2003006

Dear Mr. Warren:

On September 27, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed an inspection at your Cooper Nuclear Station. The enclosed integrated inspection report documents the inspection findings which were discussed on October 9, 2003, with Mr. J. Christensen, acting Site Vice President, 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, the NRC identified five findings that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC also determined that there were four violations associated with these findings. 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 76011-4005; 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 2.790 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
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Docket: 50-298
License: DPR-46

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NRC Inspection Report 05000298/2003006
w/Attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket.:	50-298
License:	DPR 46
Report No.:	05000298/2003006
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	P.O. Box 98 Brownville, Nebraska
Dates:	June 29 through September 27, 2003
Inspectors:	S. Schwind, Senior Resident Inspector S. Cochrum, Resident Inspector G. Replogle, Senior Resident Inspector B. Baca, Health Physicist P. Elkmann, Emergency Preparedness Inspector
Approved By:	K. Kennedy, Chief Project Branch C Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000298/2003006; 06/29/2003 - 09/27/2003; Cooper Nuclear Station: Licensed Operator Requalifications, Personnel Performance During Nonroutine Evolutions, Operability Evaluations, Event Followup, Identification and Resolution of Problems.

The report covered a 3-month period of inspection by resident inspectors and announced inspections by a regional emergency preparedness inspector and a health physics inspector. Five Green noncited violations, with multiple examples, and one green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, “Significance Determination Process.” 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. A self-revealing, noncited violation of 10 CFR 55.46(c) was identified regarding differences between the simulator and the plant in response to a manual reactor scram from high power levels. This resulted in negative training provided to licensed operators and contributed to problems during recovery from an actual reactor scram on May 26, 2003.

  This finding is more than minor since deficiencies in the operator training program could become a more significant safety concern if left uncorrected. The finding is of very low safety significance since it did not involve an exam or operating test but did involve a simulator fidelity issue which impacted operator actions (Section 1R11.2).

- Green. Two examples of a noncited violation of Technical Specification 5.4.1(a) occurred regarding the failure to follow station procedures during recovery from a reactor scram. In the first example, operators failed to lower the reactor feed master level controller in accordance with the procedure. In the second example, operators secured the high pressure coolant injection system by an alternate means not allowed by the procedure in use at the time. This alternate means rendered the system inoperable.

  This finding is more than minor since it involved human performance errors during a transient. This finding is of very low safety significance since it did not represent an actual loss of safety function. In addition, it also has crosscutting aspects associated with problem identification and resolution since it was incorrectly classified in the corrective action program (Section 1R14).

- Green. The inspectors identified a noncited violation of Technical Specification 5.5.10(c) because the licensee failed to maintain the Technical Specification Bases consistent with the Update Final Safety Analysis Report. These inconsistencies led to the decision to unnecessarily declare Division II of the residual heat removal system inoperable for approximately 3 days.

This finding is more than minor since it affected the availability of the residual heat removal system. This finding is of very low safety significance since it did not represent an actual loss of a safety function (Section 1R15).

- Green. A self-revealing finding was identified regarding the licensee's failure to adequately control maintenance on a condensate storage tank outlet valve, which resulted in lowering of main condenser vacuum on three separate occasions. The valve position indication had been installed backward following maintenance which led to the valve being mispositioned.

  This finding is more than minor since it adversely affected the availability and reliability of the power conversion system (main condenser and bypass valves). This finding is of very low safety significance, since there was no loss of safety function of the main condenser or bypass valves. In addition, it has crosscutting aspects associated with problem identification and resolution based on the number of opportunities to identify the error during and after the maintenance (Section 4OA3).

Cornerstone: Initiating Events

- Green. A self-revealing noncited violation of Technical Specification 5.4.1(a) occurred when operators failed to follow the station tagout procedure. Operators failed to correctly restore a feedwater heater level control valve to automatic following corrective maintenance. This contributed to a loss of feedwater heating and a reactor power transient.

  This finding is more than minor since it involved human performance errors which contributed to a transient. This finding is of very low safety significance since it did not contribute to the likelihood of a loss of coolant accident, a reactor trip and loss of mitigation equipment, a fire, or a flooding event. In addition, it has crosscutting aspects associated with human performance. The operating crew did not follow station management expectations for use of human error prevention tools during this activity (Section 4OA2).

B. Licensee-Identified Violation

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

REPORT DETAILS

The plant was in a forced outage at the beginning of this inspection period. On July 2, 2003, the reactor was restarted and achieved 100 percent reactor power on July 4. On July 9, reactor power was reduced to approximately 82 percent for approximately 2 hours due to a loss of feedwater heating. On September 12, 19, and 26 reactor power was reduced to approximately 65 percent for planned maintenance. The reactor returned to full power operation 2 days after each respective power reduction.

1. REACTOR SAFETY

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

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Alignment Inspections

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

- Service water (SW) system, Division II on July 10. This inspection included a review of Notification 10258339, which documented a mispositioned component, while restoring the system following a planned maintenance activity.

- Core Spray (CS) system, Division 1 while Division II was inoperable for planned maintenance on July 16. The walkdown included portions of the system in the control room, the Division I critical switchgear room, and Elevation 859 in the reactor building.

- Residual heat removal (RHR) system, Division I while Division II was inoperable for planned maintenance on August 4. The walkdown included portions of the system in the control room and on Elevations 931, 903, and 859 in the reactor building.

- High pressure coolant injection system (HPCI) follow system restoration from planned maintenance on August 14. The walkdown included portions of the system in the HPCI pump room and the control room.

- SW system, Division II while Division I was inoperable for planned maintenance on August 15. The walkdown included portions of the system in the intake structure and the control room.

Complete Equipment Alignment Inspections

On July 9, the inspectors performed one complete system alignment inspection of the RHR system, Division 1. The inspectors verified that the system was in the appropriate configuration per the system operating procedures, and that it was installed and capable of performing its design functions as described in the Updated Final Safety Analysis Report (USAR). A review of maintenance work orders and corrective action documents for the past 12 months was also performed. A walkdown of the system was performed to assess material condition such as system leaks and housekeeping issues that could adversely affect system operability.

b. Findings

No findings of significance were identified

1R05 Fire Protection

a. Inspection Scope

The inspectors performed 11 fire zone walkdowns to determine if the licensee was maintaining those areas in accordance with its 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 materials 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 9A, cable spreading room on July 18
- Fire Zone 7A, RHR SW booster pump and service air compressor area on July 18
- Fire Brigade Locker on July 25
- Fire Zone 11B, south turbine building basement on July 29
- Fire Zone 4D, motor generator set oil pump area on August 12
- Fire Zone 4C, fuel pool heat exchanger and reactor water cleanup area on August 13
- Fire Zone 1C, Division I RHR pump room on September 16
- Fire Zone 1A, reactor core isolation cooling (RCIC) and CS pump room on September 17
- Fire Zone 1B, CS pump room on September 17

- Fire Zone 1D, Division II RHR pump room on September 17

- Fire Zone 1E, HPCI pump room on September 17

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors observed cleaning and inspection activities on RHR Heat Exchanger B performed on July 7, 2003, and reviewed the last set of performance test data for this heat exchanger taken on November 4, 2001. A review of the heat exchanger performance evaluation was conducted to identify potential deficiencies that could mask degraded performance. The inspectors reviewed the type, location, and calibration of instrumentation used to acquire the data to verify its acceptability for the evaluation. The evaluation review was conducted and documented in accordance with Performance Evaluation Procedure 13.17, “Residual Heat Removal Heat Exchanger Performance Testing,” Revision 10. One sample was completed during this inspection.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalifications

.1 Quarterly Requalification Training Review

a. Inspection Scope

The inspectors observed two sessions of licensed operator requalification training in the plant simulator on July 31 and on August 15. The training on July 31 evaluated the operators’ ability to recognize, diagnose, and respond to a loss of annunciator alarms and a recirculation pump trip. The August 15 training evaluated the operators’ ability to recognize, diagnose, and respond to a jet pump failure, turbine trip, steam leak, and fuel failure. Observations were focused on the following key attributes of operator performance:

- Crew performance in terms of clarity and formality of communication

- Ability to take timely, appropriate actions

- Prioritizing, interpreting, and verifying alarms

- Correct implementation of procedures, including the alarm response procedures
- Timely control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by the shift supervisor, including ability to identify and implement appropriate Technical Specifications (TS) requirements, reporting, emergency plan actions, and notifications
- Group dynamics involved in crew performance

The inspectors also verified that the simulator response to the training scenario closely modeled expected plant response during an actual event.

b. Findings

No findings of significance were identified.

.2 Simulator Fidelity During Scrams From High Power

a. Inspection Scope

During the postevent review of a manual reactor scram which occurred May 26, the licensee attempted to validate simulator response to the transients. The inspectors reviewed the conclusions of the validation effort to determine if any negative training was provided to licensed operators as a result of simulator fidelity issues. One sample was completed during this inspection.

b. Findings

Introduction. A Green, self-revealing, noncited violation (NCV) was identified regarding simulator response to a transient condition.

Description. As discussed in Section 1R14.1 of this report, control room operators observed high main turbine vibrations on May 26. Reactor power was reduced to approximately 90 percent; however, when this failed to correct the condition, operators recognized the need to manually scram the reactor. The operating crew conducted a brief of scram recovery actions and initiated a manual reactor scram. With the exception of the main turbine, all safety-related and major balance-of-plant equipment was operable; however, during scram recovery actions, reactor vessel water level decreased to approximately -30 inches on the wide-range instrument, which exceeded the low-low (Level 2) reactor water level setpoint of -25.6 inches. This, in turn, caused the HPCI and RCIC systems to initiate, recirculation pumps to trip, and an alternate rod insertion signal to initiate. These actuations were an unexpected response to what should have been an uncomplicated scram and compounded recovery efforts by contributing to the stratification of the reactor vessel and a subsequent violation of the TS cooldown rates and pressure-temperature limits. These aspects of the transient are discussed further in Sections 1R14.1, 4OA3, and 4OA7 of this report.

As part of the post-event review, the licensee re-created this transient on the simulator to validate the simulator computer model. During this scenario, reactor vessel level decreased to only -20 inches, which was not as low as the level experienced during the May 26 scram, and not low enough to cause the same actuations on the Level 2 reactor vessel water level. Upon further review, the inspectors learned that the licensee had previously identified this simulator fidelity issue in 2000 after a scram from high power initiated by a turbine trip. During the review following that event, the licensee identified that the simulator computer code did not accurately model shrink and swell in the reactor vessel. To correct this, the licensee implemented batch files in the simulator model which corrected this discrepancy for specific simulator training scenarios that involved a transient initiated by a main turbine trip. Similar batch files were not implemented for scenarios where the transient was initiated by a reactor scram from high power. As a result, simulator response differed significantly from plant response during transients initiated by reactor scrams from high power. This simulator modeling error was not included in the regular briefing that licensed operators received during their training cycle. Consequently, control room operators were not trained to anticipate a Level 2 reactor vessel water level signal accompanied by a loss of recirculation flow and the initiation of HPCI, RCIC, and alternate rod insertion following a manual reactor scram from high power.

Prior to restarting the plant, the licensee implemented several corrective actions for this issue, including correcting the simulator response and lowering the Level 2 setpoint to -33.4 inches, since the existing setpoint (-25.6 inches) was recognized as being overly conservative. The TS limit for the Level 2 setpoint was -42 inches.

Analysis. This finding involved a licensed operator training deficiency regarding plant response to high power reactor scrams. Therefore, this finding affected the Mitigating Systems Cornerstone since it impacted the operators' response to mitigate the consequences of this transient and was considered more than minor since deficiencies in the operator training program could become a more significant safety concern if left uncorrected. Based on the results of a Significance Determination Process (SDP) using Manual Chapter (MC) 0609, Appendix I, this finding was determined to have very low safety significance, since it did not involve an exam or operating test but did involve a simulator fidelity issue which impacted operator actions.

Enforcement. Title 10 of the Code of Federal Regulations (CFR), Part 55.46(c), requires that plant referenced simulators used for operating tests or to meet experience requirements must demonstrate expected plant response to transient conditions to which the simulator was designed to respond. The Cooper Nuclear Station simulator was designed to respond to reactor scrams; however, the simulator response differed from actual plant response in that a normal reactor scram would cause a Level 2 actuation in the plant, but not in the simulator. The failure to adequately model plant response in the simulator, discovered on May 27, 2003, is a violation of 10 CFR 55.46(c). This violation is being treated as a noncited violation (50-298/0306-001) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into their corrective action program (CAP) as Notification 10249452.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed four equipment performance issues to assess the licensee's implementation of their maintenance rule program. The inspectors verified that components that experienced performance problems were properly included in the scope of the licensee's maintenance rule program, and the appropriate performance criteria were established. 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 15. The inspectors reviewed the following equipment performance problems:

- Failure of 4160 V Breaker EG1 to close during surveillance testing on June 18 (Notification 10254105)
- Failure of HPCI Minimum Flow Valve HPCI-MO-25 to open on June 30 during HPCI testing (Notification 10256194)
- Main turbine blade failure on May 26 (Significant Condition Report (SCR) 2003-1169)
- Failure of the dc output breaker for 250 Vdc Battery Charger B on June 26 (Resolve Condition Report (RCR) 2003-1394)

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed three 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:

- Corrective maintenance on Emergency Diesel Generator (EDG) 1 to replace the digital reference unit on April 2 (Work Order 4303040)

- Corrective maintenance on EDG 2 to replace the digital reference unit on July 13 (Notification 10258805)

- Corrective maintenance on Relief Valve RHR-RF-15 due to excessive leakage. This rendered RHR Division A inoperable for 3 days beginning on July 16 (Work Order 4322246)

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions

a. Inspection Scope

For the two nonroutine events described below, the inspectors reviewed operator logs, plant computer data, and strip charts to determine what occurred and how the operators responded and to determine if the response was in accordance with plant procedures:

- On May 26, the inspectors responded to the control room shortly after control room operators manually scrammed the reactor due to high main turbine vibrations. Operators initially responded to the high vibrations by lowering reactor power and commencing a normal reactor shutdown. At approximately 90 percent reactor power, the power reduction was suspended due to rising turbine vibrations and the reactor was manually scrammed. The inspectors observed and evaluated the followup actions by the operators, actions required by procedures and monitoring of plant conditions. Other aspects of this event are discussed in Sections 1R11.2, 4OA3, and 4OA7.

- On June 29, the inspectors observed control room operators perform a reactor startup following a forced outage to repair damage to the main turbine. Observations were focused on reactivity management and attributes of human performance such as procedure adherence, communications, self-checking, and peer-checking.

b. Findings

Introduction. Two examples of a licensee identified, Green, NCV occurred regarding the failure to follow procedures for a reactor scram and HPCI system operation.

Description. On May 26, a manual reactor scram from 90 percent reactor power was initiated due to high vibration on main turbine. Attempts to perform a normal plant shutdown were halted due to rising main turbine vibrations as power was reduced. Following the scram, reactor vessel water level dropped below the Level 2 setpoint, resulting in primary containment isolation system Groups 2, 3, and 6 isolations, start of HPCI and RCIC systems, and a trip of the reactor recirculation pumps. HPCI and reactor feed pumps (RFP) A and B were secured due to reactor vessel water level rapidly recovering; however, reactor water exceeded the Level 8 setpoint, resulting in the trip of RCIC due to high reactor vessel water level. Rapid restart of RFP B was performed and reactor vessel water level was stabilized within the shutdown band.

During the licensee's postevent review, it was discovered that the control room operators did not decrease the reactor water level setpoint as called for in the scram procedure immediate actions. Attachment 1 of General Operating Procedure 2.1.5, "Reactor Scram," Revision 41, required the control room operators to lower the reactor feedwater master level controller from 37 inches to 15 inches. This error was discovered and corrected by the operators while rapidly restarting RFP B. Lowering of the reactor feed master level controller is required to reduce the likelihood of exceeding the Level 8 setpoint, which complicates scram recovery.

It was also discovered in the postevent review that the control room operators did not use the correct procedure for removing HPCI from service during the scram recovery. Control room operators noted reactor vessel level recovering rapidly and determined HPCI injection was not required. The operators tripped the HPCI turbine using guidance from Attachment 4 of Emergency Operating Procedure 5.8, "Emergency Operating Procedures (EOPs)", Revision 18. This procedure directed operators to press the HPCI turbine trip button, wait until the turbine stopped rotating, then place the auxiliary oil pump switch in pull-to-lock. This defeated the HPCI safety function by preventing further auto initiations. EOP 5.8 had not been entered by the crew at this point. However, EOP 1A, "RPV Control," Revision 12, was in use which directed HPCI operations in accordance with System Operating Procedure 2.2.33.1, "High Pressure Coolant Injection System Operations," Revision 14. This procedure contained specific guidance on securing HPCI and placing it in a standby lineup. General Operating Procedure 2.1.5, "Reactor Scram," Revision 41, Attachment 2, "Reactor Water Level Control," also directed operation of HPCI in accordance with System Operating Procedure 2.2.33.1. After the plant was shut down, and stabilized, the operators referenced System Operating Procedure 2.2.33.1 and restored HPCI to standby alignment.

Analysis. This finding affected the Mitigating Systems Cornerstone and was considered more than minor since it affected the cornerstone attribute of human performance. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance since it did not represent an actual loss of safety function.

This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on the licensee's classification of the problem identification reports written to document the procedural violations. These reports were initially classified as department dispositions which are considered enhancements or issues not of the level of RCRs and are to be resolved at the responsible manager's discretion. Both reports were later downgraded and removed from the corrective action program. However, in accordance with Administrative Procedure 0.5PIR, "Problem

Identification, Review, and Classification," Revision 12, both reports met the criteria for an RCR, which would require an apparent cause and/or corrective actions to resolve the conditions.

Enforcement. TS 5.4.1(a) requires that licensees establish, implement, and maintain written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for combating emergencies and other significant events, such as reactor scrams. In the first example, operators did not lower the reactor feed master level controller from 37 inches to 15 inches in accordance with General Operating Procedure 2.1.5, "Reactor Scram," Revision 41, Attachment 1. In the second example, operators failed to secure HPCI and place it in a standby condition in accordance with System Operating Procedure 2.2.33.1, "High Pressure Coolant Injection System Operations," Revision 14. These findings occurred on May 26, 2003, and represent two examples of a violation of TS 5.4.1(a) violation. This violation is being treated as a noncited violation (50-298/0306-002) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered these issues into their CAP as Notifications 10249930 and 10249920.

1R15 Operability Evaluations

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 systems remained available so 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 USAR, TS, and associated system design criteria documents to determine if operability was justified. The inspectors reviewed the following equipment conditions and associated operability evaluations:

- Drywell Inlet Outboard Isolation Valve PC-AOV-238AV slow stroke time during inservice testing (Notification 10261196)
- Structural integrity of feedwater heaters due to wall thinning and postulated external pressure events (Notification 10214877)
- Alternative test methods used during postmaintenance testing following drywell head bolt replacement (Notification 10261745)
- Excessive seat leakage in Relief Valve RHR-RF-15 (Notification 10260448)

b. Findings

Introduction. A Green NCV was identified when the licensee unnecessarily declared the Division II RHR pump inoperable due to misleading and incorrect statements in the TS Bases.

Description. On July 13, the licensee identified seat leakage through Relief Valve RHR-RF-15 as the source of in-leakage into the suppression pool. The valve was leaking approximately 13 gallons per minute, which necessitated transferring water from the torus daily in order to maintain suppression pool level within TS limits. This relief valve provides overpressure protection for the Division II RHR discharge piping. The valve discharge is directed through the primary containment boundary and terminates beneath the surface of the suppression pool; therefore, it has a passive function as a primary containment boundary.

The seat leakage in RHR-RF-15 was considered to be a degraded condition and was documented in Notification 10258777. An operability determination was subsequently performed which concluded that neither the active nor passive functions of the valve were affected. The operability determination accurately concluded that, per the USAR, the valve only acted as a containment boundary, not a primary containment isolation valve (PCIV), since it did not have an active function to close on an isolation signal, was contained in a closed loop system which does not communicate directly with the containment atmosphere, and there were no through-body leaks on the valve. Furthermore, there was no maximum leakage criteria for this valve in accordance with 10 CFR Part 50, Appendix J. Since the amount of seat leakage was inconsequential compared with rated flow from the RHR pumps, there was no impact on operability of Division II of the RHR system.

Three days later, on July 16, additional questions were raised by the licensee regarding the classification of RHR-RF-15 as a containment boundary rather than a PCIV. These questions arose from statements contained in Section B3.6.1.3 of the TS Bases, which provided additional information on the applicability of TS Limiting Condition for Operation (LCO) 3.6.1.3, “PCIV operability.” Section B3.6.1.3 stated that valves covered by the LCO were listed in Table V-2-2 of the USAR along with their required stroke times. RHR-RF-15 was listed on this table. This section also described the operability of manual valves and other passive isolation devices which implied that the LCO was applicable to RHR-RF-15. Based on these statements, the licensee concluded that TS 3.6.1.3 applied to RHR-RF-15 and, even though there was no acceptance criterion for leakage, the valve was inoperable as a PCIV due to the leakage. The action statement for TS 3.6.1.3 required isolation of an inoperable PCIV within 4 hours; however, since RHR-RF-15 was an ASME code relief valve, there were no isolation valves that could be used to accomplish this. The only option was to completely isolate the Division II RHR system, which required isolation of the pressure maintenance system. With the pressure maintenance system isolated, the licensee could not demonstrate that the RHR discharge piping would remain completely filled with water as required by the TS; therefore, Division II of RHR was declared inoperable.

On July 19, the licensee implemented a temporary modification which increased the lift setpoint of RHR-RF-15 to stop the leakage. This rendered the valve's active safety function inoperable. The licensee was able to demonstrate that an additional relief valve in the system could provide the same overpressure protection. Division II of the RHR system was then declared operable.

While conducting a root cause investigation into this event, the licensee concluded that RHR-RF-15 was, in fact, not a PCIV and, as the original operability determination concluded, TS 3.6.1.3 was not applicable. The licensee was able to demonstrate that Table V-2-2 in the USAR was actually a schedule of containment penetration isolation devices which clearly included additional items such as blank flanges. In addition, the statements in Section B3.6.1.3 of the TS Bases, which implied that TS 3.6.1.3 was applicable to passive isolation devices, were included in the Bases in error. Those statements were included in the original generic Improved Technical Specification Bases which were adopted by the licensee in 1997 during conversion to Improved Technical Specifications. The statements were not consistent with the USAR or the original licensing basis, which considered only active isolation devices as PCIV's; all other passive isolation devices were considered to be containment barriers which were governed by TS 3.6.1.1. This was consistent with statements in TS Bases B3.6.1.1. Therefore, it was the inconsistent statements in TS Bases which led to the incorrect conclusion that RHR-RF-15 was an inoperable PCIV. This, in turn, led to inappropriate actions taken to render Division II of the RHR system inoperable for 3 days.

Analysis. This finding affected the Mitigating Systems Cornerstone and was considered more than minor since it affected the availability of a mitigating system (RHR). Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance, since it did not represent an actual loss of a safety function.

Enforcement. TS 5.5.10.c requires provisions to ensure that the TS Bases are maintained consistent with the USAR. The statements in Section B3.6.1.3 which referred to passive isolation devices as PCIV's were inconsistent with the USAR. These statements were incorrect and led to the inappropriate decision to declare a division of RHR inoperable on July 16, 2003. This violation of TS 5.5.10.c is being treated as a noncited violation (50-298/0306-003) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into their CAP as Notification 10260448.

1R17 Permanent Plant Modifications

.1 Annual Review

a. Inspection Scope

Radioactive Waste System Modification

The inspectors reviewed plant modification CED 6012041, “Rad Waste,” which installed a drain valve in the radioactive waste header to allow monitoring of pressure during water transfers. The review included the safety screen to determine if the modification represented an unreviewed safety question.

RHR Steam Condensing Mode Modification

The inspectors reviewed plant modification CED 6012122, which was implemented to remove the steam condensing mode of the RHR system. This seldom-used mode of the system was determined to be susceptible to hydrogen accumulation which posed an explosive hazard. The review included the safety screen to determine if the modification represented an unreviewed safety question and a daily review of system configuration during implementation, since RHR was required for shutdown cooling at the time.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing

a. Inspection Scope

The inspectors reviewed or observed five selected postmaintenance tests to verify that the procedures adequately tested the safety function(s) 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 maintenance activities were included in the scope of this inspection:

- Corrective maintenance on Hydrogen Valve H2-B-51 on July 2 (Work Order 4320231)

- Replacement of the EDG 2 digital reference unit on July 13 (Work Order 4321385)

- Corrective maintenance on Relief Valve RHR-RF-15 on July 19 (Work Order 4322246)

- Corrective maintenance on the reactor building ventilation controller on September 25 (Work Order 4312934)

- Preventive maintenance on 4160 V Breaker 1AN on September 25 (Work Order 4296891)

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed or reviewed the following four 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 TS requirements, the USAR, and licensee procedural requirements:

- 6.HPCI.103, “HPCI IST [Inservice Test] and 92 Day Test mode Surveillance Operation,” Revision 22, performed on July 1

- 6.2RBM.302, “RBM [Rod Block Monitor] Channel Calibration,” Revision 6, performed on July 23

- Maintenance Procedure 7.3.23, “24V RPS [Reactor Protection System] Battery Performance Discharge Test,” Revision 10, performed on August 20

- 6.2CS.302, “CS Loop B Pump Time Delay Channel Calibration (Div 2),” Revision 5, performed on August 21

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Configuration Change 4322229, which was implemented on July 19 to increase the lift setpoint on Relief Valve RHR-RF-15 to reduce the amount of seat leakage. The inspectors verified that the change did not require NRC approval prior to implementation and that adequate controls on the installation existed.

b. Findings

No findings of significance were identified.

1EP2 Alert Notification System Testing

a. Inspection Scope

The inspectors discussed with licensee staff the status of offsite siren and tone alert radio systems and observed a scheduled biweekly silent test of the siren system to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Revision 1; Federal Emergency Management Agency (FEMA) Report REP-10, "Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants;" and Revision 10 (dated January 2003) to the licensee's FEMA-approved alert and notification system design report. The inspector also reviewed the following procedures:

- EPDG 2, Attachment C-1, "Semi-Monthly Alert and Notification System Siren Testing," Revision 9
- EPDG 2, Attachment C-5, "Annual Full Cycle Sounding of Alert and Notification System Sirens," Revision 8
- EPDG 2, Attachment C-6, "Annual Fixed Siren Maintenance," Revision 7
- EPIP 5.7.27, "Alert and Notification System," Revision 16
- EPIP 4.7.27.2, "False Activation of Alert and Notification System Sirens," Revision 3

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing

a. Inspection Scope

The inspector discussed with licensee staff the status of primary and backup systems for mobilizing the emergency response organization during an emergency to determine the licensee's ability to staff emergency response facilities in accordance with the licensee emergency plan and the requirements of 10 CFR Part 50, Appendix E. The inspector also reviewed the following documents related to the emergency response organization augmentation system:

- EPDG 2, Attachment E-3, “Bi-Monthly ERO Call-In Test,” Revision 10
- EPDG 2, Attachment E-4, “Weekly Pager Test,” Revision 0
- EPDG 2, Attachment E-5, “Monthly Verification of ANS Module Phone Numbers,” Revision 0
- Procedure 0-EP-02, “Configuration Control of the Automated Notification System,” Revision 2

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspector performed an on-site review of Revision 30 to Emergency Plan Implementing Procedure 5.7.1, “Emergency Classification,” submitted May 14, 2003. This revision: (1) required classification of a Notification of Unusual Event following receipt of information from off-site authorities about a credible site specific threat, (2) clarified classification of seismic events when monitoring equipment is out of service, (3) clarified determination of a loss or potential loss of fuel cladding when reactor vessel water level cannot be determined, (4) revised setpoints for the determination of a loss of fuel cladding based on main steam radiation levels to account for changed radiological operating conditions, and (5) clarified determination of a loss of the containment barrier. The revision was compared to its previous revision; to the criteria of NUREG-0654, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants,” Revision 1; and to the requirements of 10 CFR 50.47(b) and 50.54(q) to determine if the revision decreased the effectiveness of the plan.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope

The inspector reviewed the following documents related to the licensee’s corrective action program to determine the licensee’s ability to identify and correct problems in accordance with 10 CFR 50.47(b)(14) and 10 CFR Part 50, Appendix E.

- Summaries of corrective actions assigned to the emergency preparedness department between April 2001 and June 2003

- RCR 2001-0390,-0781,-1542, 2002-0182,-0640,-0904,-1181, and -2610

- Notifications 10176466, 10197926, and 10233870

- Procedure 0.5.NAIT, “Corrective Action Implementation and Nuclear Action Item Tracking,” Revision 18

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed the licensee perform two emergency preparedness drills on August 27 and September 24. Observations were conducted in the control room, technical support center, and 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 August 27 and September 24.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY
Cornerstone: Occupational Radiation Safety [OS]

2OS2 ALARA (as low as is reasonably achievable) Planning and Controls

a. Inspection Scope

The inspector interviewed radiation protection personnel and radiation workers involved in high dose rate, high exposure, and airborne area work activities. The inspector assessed the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, and high radiation areas; radiation worker practices; and work activity dose results against procedural and regulatory requirements. No high exposure work activities in high radiation or airborne areas were performed during the inspection. Therefore, this aspect could not be evaluated.

The inspector interviewed radiation protection staff and other radiation workers to determine the level of planning, communication, ALARA practices, and supervisory oversight integrated into work planning and work activities. The inspector reviewed initial and emergent work scopes and estimated man-hours provided to the radiation protection group for accuracy. In addition, the following items were reviewed and compared with procedural and regulatory requirements to assess the licensee's program to maintain occupational exposures ALARA:

- Plant collective exposure history for the past 3 years, current exposure trends, source term measurements, and 3-year rolling average dose information

- ALARA program procedures

- Processes, methodology, and bases used to estimate, justify, adjust, track, and evaluate exposures

- Four ALARA packages, which included prejob, in-progress, and postjob reviews with associated radiation work permits, from Refueling Outage 21 resulting in the highest personnel collective exposures (2003-AL-01, "Refuel Floor Activities;" 2003-AL-02, "ISI/EC Activities;" 2003-AL-03, "Target Rocks;" and 2003-AL-09, "Drywell Scaffolding")

- The use and result of administrative and engineering controls to achieve dose reductions

- Individual exposures of selected work groups (health physics, operations, and maintenance)

- Temporary and permanent shielding program and implementation

- Plant source term evaluation and control strategy/program
- Hot spot tracking and reduction program (2001 Hot Spot Reduction Plan and Hot Spot Trend Analysis August 2002 through January 2003)
- ALARA Committee meeting minutes and presentations since the last inspection
- Declared pregnant worker and embryo/fetus dose evaluation, monitoring, and controls
- Summary of corrective action documents written since the last inspection and selected documents relating to exposure tracking, higher than planned exposure levels, radiation worker practices, and repetitive and significant individual deficiencies.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 PI Verification

a. Inspection Scope

The inspectors sampled licensee performance indicators (PI) listed below for the period July 1, 2002, through June 30, 2003. The definitions and guidance of NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revision 2, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of PI data reported during the assessment period. Licensee PI data were reviewed against the requirements of Procedure 0-PI-01, “Performance Indicator Program,” Revision 10.

Reactor Safety Cornerstone

- RHR system unavailability
- Safety system functional failures
- Reactor coolant system (RCS) activity

The inspectors reviewed a selection of licensee event reports (LERs), portions of operator log entries, monthly reports, and PI data sheets to determine whether the licensee adequately collected, evaluated, and distributed PI data for the period reviewed.

Emergency Preparedness Cornerstone:

- Drill and exercise performance
- Emergency response organization participation
- Alert and notification system reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, Notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. Licensee performance was reviewed against the requirements of Procedures EPIP 5.7.1, "Emergency Classification," Revisions 28, 29, and 30; and EPIP 5.7.6, "Notification," Revision 38. The inspector reviewed a sample of 12 emergency responder qualification and training records, and a sample of 10 drill participation records. The inspector reviewed alert and notification system testing procedures, maintenance records and a 100 percent sample of siren test records.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Unplanned Power Change Due to Loss of Feedwater Heating

a. Inspection Scope

The inspectors reviewed the licensee root cause investigation regarding a feedwater transient which occurred while restoring a feedwater heater level control valve to service following corrective maintenance.

b. Findings

Introduction. A self-revealing, Green NCV was identified for failure to follow the tagout procedure.

Description. On July 4, operators identified that Valve CD-LCV-60A, the Feedwater Heater A5 level control valve, was not controlling level correctly. Subsequent troubleshooting determined that the air operator for this valve required replacement. On July 6 the valve was tagged closed by Tagging Order CD-1-4319983, which required the valve to be held in the closed position by a manual jacking device permanently installed on the valve operator. The jacking device was capable of holding the valve fully open or fully closed and had a neutral position, which allowed full travel of the valve as controlled by the air operator. Upon completion of the maintenance, operators were dispatched to restore Valve CD-LCV-60A in accordance with Clearance Order CD-1-4319983, which required the jacking device to be left in the neutral position; however, operators incorrectly positioned the jacking device and left it in the full open position. At the same time, an operator was stationed at a remote instrument rack to modulate the control air signal to Valve CD-LCV-60A while placing it in neutral to maintain level in the feedwater heater. Upon indication that the valve was fully open, the operator adjusted the air signal to Valve CD-LCV-60A in an attempt to modulate the valve closed. Since the valve was not moving, the air signal was adjusted to the point where it provided a fully closed signal. Consequently, Valve CD-LCV-60A failed the postmaintenance test and was left jacked fully open with a fully closed demand signal.

On July 7, the licensee determined that the failure of the postmaintenance test was due to incorrect positioning of the jacking device on Valve CD-LCV-60A. As a result, operators were dispatched a second time to reposition the jacking device to the neutral position. The clearance order specifically stated to slowly restore the jacking device to the neutral position and to allow Valve CD-LCV-60A to respond. It also required that an operator be stationed at the heater level controller to monitor and adjust heater level when the jacking device was restored to neutral. The operator at the remote instrument rack was unaware that there was a fully closed demand signal on the valve and was instructed only to monitor the position of Valve CD-LCV-60A. As soon as the jacking device was placed in neutral, Valve CD-LCV-60A went fully closed which caused high level alarms in Feedwater Heater A5 and Moisture Separators A and C. The resulting loss of feedwater heating caused feedwater temperature to decrease by approximately 22°F, and reactor power increased to approximately 104 percent. In response, control room operators immediately reduced reactor power to approximately 82 percent by decreasing reactor recirculation flow and the operator stationed at the instrument rack manipulated the air signal to Valve CD-LCV-60A to open the valve. The combination of these two actions reduced level in Feedwater Heater A5 and Moisture Separators A and C.

Analysis. This finding affected the Initiating Events Cornerstone and was considered more than minor since it affected the cornerstone attribute of human performance. Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance since it did not contribute to the likelihood of a loss of coolant accident, a reactor trip and loss of mitigation equipment, a fire, or a flooding event.

This finding had crosscutting aspects associated with human performance. This assessment was based on the licensee's root cause investigation, which concluded that the prejob brief for this evolution failed to consider the operational impact of the activity. The brief did not include a discussion of items such as reactivity management or contingencies for an unanticipated system response. Administrative Procedure 0-HP-POLICY, "Human Performance Policy," Revision 3, lists prejob briefs as a human error prevention tool that all workers are expected to use for all tasks.

Enforcement. TS 5.4.1(a) requires that licensees establish, implement, and maintain written procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Appendix A recommends procedures for locking and tagging equipment. Administrative Procedure 0.9, "Tagout," Revision 36, Section 13.5, requires that persons clearing tags on a component remove the tag and return the component to the position specified by the tag release sheet. Operators failed to implement this requirement on July 6, 2003, when they failed to return the manual jacking device on Valve CD-LCV-60A to the neutral position as specified on the tag release sheet. This violation is being treated as a noncited violation (50-298/0306-004) consistent with Section VI.A of the NRC Enforcement Policy. The licensee entered this issue into their CAP as SCR 2003-1432.

.2 Annual Sample Review of Emergency Preparedness Condition Reports

a. Inspection Scope

The inspector selected 11 corrective action reports regarding emergency preparedness for a detailed review. The entries were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspector evaluated corrective actions against the requirements of Procedure 0.5.EVAL, “Preparation of Condition Reports,” Revision 2, and Procedure 0.5.PIR, “Problem Identification, Review, and Classification,” Revision 12.

b. Findings and Observations

There were no findings identified associated with the reviewed corrective action reports; however, the inspector identified that in one case (RCR 2002-0182) the licensee failed to address generic aspects of an identified condition. The licensee identified that the internal telephone system was left in a condition which prevented use of the automated system to mobilize the emergency response organization following work performed on the internal telephone system by company personnel. The licensee determined that the apparent cause of this condition was that company telecommunications workers [who were not assigned to the site] did not have procedures for working on the plant telephone system. The corrective action report identified that other kinds of work were done on-site by company workers who also did not use procedures and that the extent of this condition required evaluation. The inspector determined that this corrective action was closed without an extent-of-condition evaluation being performed.

.3 Cross-References to Problem Identification and Resolution Findings Documented Elsewhere

Section 1R14 describes that the licensee had identified problems with failure to follow General Operating Procedure 2.1.5, “Reactor Scram,” Revision 41, and System Operating Procedure 2.2.33.1, “High Pressure Coolant Injection System Operations,” Revision 14. The problem identification reports for the above issues met the criteria of an RCR, which would require an apparent cause and or corrective actions to resolve the conditions. These reports were entered into the CAP as department dispositions, which are considered enhancements and are to be resolved at the responsible manager’s discretion, but were later downgraded and removed from the CAP.

4OA3 Event Followup

.1 Lowering Main Condenser Vacuum

a. Inspection Scope

The inspectors responded to the control room on April 26 after a report of lowering main condenser vacuum. The immediate cause was determined to be the loss of a loop seal in the radioactive waste (RW) system. Operators responded to the transient by lowering reactor power to approximately 63 percent and isolating the loop seal from the main condenser. The inspectors verified that the licensee was operating the plant within the limits specified in the TS, the appropriate abnormal operating procedures were being implemented, and that the actions taken to stabilize the plant were prompt and appropriate. As part of the followup to this event, the inspectors reviewed normal and abnormal procedures and interviewed plant personnel to evaluate the response to this event.

b. Findings

Introduction. A self-revealing Green finding was identified regarding the licensee's failure to adequately control maintenance on Condensate Storage Tank Outlet to Reactor Building Valve CM-V-135, which resulted in lowering of main condenser vacuum on three separate occasions.

Description. On April 26, the inspectors responded to the control room after a report of lowering main condenser vacuum. Control room operators responded to the degraded condenser vacuum by reducing reactor power to approximately 63 percent and isolating the RW loop seal from the main condenser by closing Fuel Pool Cooling Drain Line Valve FPC-V-57. Additional degraded main condenser vacuum events occurred later on April 26 and on May 3 requiring power reduction and isolation of Valve FPC-V-57.

Based on plant data, operator logs, and engineering troubleshooting, the first event on April 26 was believed to have resulted from air intrusion to the main condenser resulting from the loss of the RW loop seal. The loss of the loop seal was thought to have resulted from admission of steam into Sump DD from the Augmented Off Gas (AOG) system after-condenser during AOG startup. Sump DD was subsequently isolated and the loop seal was refilled. Approximately 5 hours after the first event, main condenser vacuum degraded rapidly and Valve FPC-C-57 was closed to isolate the entire header associated with Sump DD. After the second event on April 26, Sump DD was verified to have been previously isolated from the loop seal, which precluded the sump and AOG from being the cause of the second event. The loop seal was also verified to be intact after the second event.

Between April 26 and May 3, troubleshooting continued to determine the cause of the degraded main condenser vacuum. On May 3, main condenser vacuum degraded rapidly and the control room operators responded by lowering reactor power to approximately 74 percent and shutting Valve FPC-V-57 to stop the event. Troubleshooting following the third event on May 3 determined that the degraded main condenser vacuum was caused by air intrusion from the evacuation of water from the standpipe for the waste surge tank. Evacuation of the standpipe resulted from the position indication of Valve CM-V-135 being installed incorrectly after maintenance during Refueling Outage 19. This condition caused Valve CM-V-135 to indicate open when is was actually shut. The normal operational position of Valve CM-V-135 is open. The misorientation of the position indication caused Valve CM-V-135 to be shut, which isolated the reactor building auxiliary condensate pump from its normal suction source and caused the pump to draw a suction from the waste surge tank standpipe. This allowed an air path to be established from the waste surge tank to the main condenser.

Analysis. This finding had crosscutting aspects associated with problem identification and resolution. This assessment was based on the licensee's root cause investigation, which determined that a number of opportunities to identify the error were missed during and after the maintenance.

This finding affected the Mitigating Systems Cornerstone and was considered more than minor since it adversely affected the availability and reliability of the power conversion system (main condenser and bypass valves). Based on the results of an SDP Phase 1 evaluation, this finding was determined to have a very low safety significance since there was no loss of safety function of the main condenser or bypass valves.

Enforcement. No violation of NRC requirements was identified regarding the failure to adequately control maintenance on Condensate Storage Tank Outlet to Reactor Building Valve CM-V-135. This finding was entered into the licensee's CAP as SCR 2003-0954.

.2 (Closed) LER 50-298/2001-003-00, Failure to Adequately Revise Procedures Resulted in Inadequate Fire Watches Under Certain Battery/Battery Charger Configurations and an Unanalyzed Condition

On May 9, 2001, the licensee determined that inadequate compensatory fire watches were posted after placing 125/250 Volt Battery Charger C in service on three separate occasions between December 1998 and July 2000. Charger B is required to support 10 CFR Part 50, Appendix R, safe shutdown requirements in certain fire zones. Compensatory fire watches are required whenever the Charger C is used in lieu of Charger B. Plant procedures were revised in 1992 to specify which fire zones required compensatory fire watches; however, not all the necessary fire watches were incorporated into the procedure until June 7, 2001. This finding was considered more than minor because it involved a potential increase in the probability of a loss of all dc power in the event of a fire. MC 0609, "Significance Determination Process," was used to assess the safety significance of this finding. The protection scheme of Figure 4-3 of MC 0609, Appendix F, was used to screen this issue. The lack of a fire watch needed to mitigate the recovery impairment (lack of procedure) was considered a degradation of detection, which required a Phase 2 evaluation. The following assumptions were made in the Phase 2 evaluation:

- The condition existed for 15 days (in a one-year period).
- Manual detection and suppression was relied upon to minimize damage to redundant divisions of equipment. No automatic fire detection exists between the divisions.
- Because of the lack of a needed fire watch, manual detection was assumed to be highly degraded. This was a conservative assumption used to establish a bounding case.
- Battery Charger B was unavailable and Battery Charger C was in service
- Fire event in Fire Area IV (Fire Zone 8D)
- Maximum transient fuel load in Zones 7A, 8E, and 8D
- According to Cooper Nuclear Station's Individual Examination of External Events, the ignition frequency for a fire in Zone 8D is 2.42E-3/year.
- Worst case - large fire in Zone 8D spreads to dc switchgear Room 1A (Zone 8E)
- A fire in Zone 8D would adversely affect the ability to reach and maintain safe shutdown conditions.
- No mitigating capability existed (bounding assumption).

The bounding event was a fire initiating in Fire Zone 8D and spreading to Zone 8E, where it could disable the dc switchgear. The Phase 2 evaluation resulted in a low to moderate safety significance. Further analysis was performed by a Senior Reactor Analyst, who determined the finding to be of very low significance (Green). This licensee-identified finding involved a violation of 10 CFR Part 50, Appendix R, Section III.L.5. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.3 (Closed) LER 50-298/2003-002-00, Technical Specification Prohibited Operation Due to Safety Relief Valve Test Failures

On May 19, the licensee received test data on eight safety relief valve (SRV) pilot valve assemblies from an offsite test facility. Four of the eight pilot valves failed to lift within their TS required lift setpoints during as-found testing. Specifically, one pilot valve, with a setpoint of 1080 ± 32.4 psig lifted at 1168 psig, two pilot valves with a setpoint of 1090 ± 32.7 psig lifted at 1130 psig and 1160 psig, respectively, and one pilot valve with a setpoint of 1100 ± 33.0 psig lifted at 1228 psig. Each of the four pilot valve assemblies was also sent to an independent test lab for further failure analysis, which indicated that the increased as-found values were due to corrosion bonding of the valve disc to the seat. The SRV's at Cooper Nuclear Station are two-stage Target Rock safety relief valves. The pilot valve assemblies have Stellite 21 discs and Stellite 6 seats. Several previous test failures at Cooper Nuclear Station were attributed to corrosion bonding in the pilot valve assembly, which is an industry-wide concern with this type of valve. The as-found pressure values for these valves were bounded by the assumptions made in the core reload analyses for Cycles 21 and 22; therefore, core performance and RCS integrity were not challenged. Although corrective actions for these past test failures did not prevent recurrence of this condition, those actions, such as changing valve disc and seat material as recommended by the vendor, were considered reasonable; therefore, no performance deficiency on the part of the licensee was identified. This finding is not suitable for SDP evaluation, but has been reviewed by NRC management and is determined to be a Green finding of very low safety significance. This licensee-identified finding involved a violation of TS 3.4.3. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.4 (Closed) LER 50-298/2003-004-00, Manual Reactor Scram Due to Main Turbine Vibration

On May 26, 2003, a manual scram from 90 percent reactor power was initiated due to main turbine vibration. Subsequent to the scram, reactor vessel water level decreased to approximately 30 inches below instrument zero, resulting in primary containment isolation system Groups 2, 3, and 6 isolations, start of HPCI and RCIC, and trip of the reactor recirculation pumps. With no reactor recirculation pumps inservice, the bottom head region of the reactor cooled rapidly, resulting in reactor vessel drain temperature lowering approximately 110°F in a one-hour period. With the lower head cooling at a higher rate than saturation temperature of the reactor vessel, the vessel drain temperature reached 168°F at a reactor vessel pressure of 488 psig, exceeding the pressure-temperature curve for the lower head region. After natural circulation was established, the bottom head heated up rapidly, causing bottom head temperatures to rise 105°F in a one-hour period. When the plant conditions allowed, shutdown cooling was placed in service, causing bottom head drain temperatures to heat up rapidly resulting in a temperature rise of 170°F in 15 minutes. This was considered to be four examples of operators failing to perform TS Surveillance Requirement 3.4.9.1, which requires verification that the RCS pressure and temperature are within limits and RCS heatup and cooldown rates are less than or equal to 100°F when averaged over a one-hour period. This finding affected the Barrier Integrity Cornerstone and was considered more than minor since failure to implement TS requirements could become a more significant safety concern if left uncorrected. Based on the results of a SDP evaluation, this finding was determined to have very low safety significance since it did not represent an actual degradation of any fission product barrier. This licensee-identified finding involved a violation of TS 3.4.9. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA5 Other Activities

The inspectors reviewed the Institute of Nuclear Power Operations' evaluation report for Cooper Nuclear Station, dated March 2002, as well as the Cooper Accrediting Team Report, dated May 2003. Neither report contained any previously unidentified safety issues.

4OA6 Meetings, Including Exit

On July 16, inspectors presented the results of the emergency preparedness inspection to Mr. D. Meyers, General Manager, Site Support, and other members of his staff who acknowledged the findings.

On July 11, inspectors presented the results of the ALARA planning and controls inspection to Mr. J. Christensen, Plant Manager, and other members of licensee management who acknowledged the findings.

On October 9, inspectors presented the results of the resident inspector activities to Mr. J. Christensen, Acting Site Vice President, and other members of his staff who acknowledged the findings.

In all cases, the inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee Identified Violations

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

- 10 CFR Part 50, Appendix R, Section III.L.5, requires that systems necessary to achieve and maintain cold shutdown shall not be damaged by fire or the fire damage limited to such systems so they can be repaired and made operable and procedures be in effect to implement such repairs. Contrary to this requirement, the licensee failed to correct deficiencies with the station's procedures, requiring compensatory actions in place of repair procedures for the swing dc battery charger. This finding was discovered on May 9, 2001, and was documented the licensee's CAP as Section 4OA7 enforcement writeup as SCR 2001-0417. This finding was only of very low safety significance, since it did not involve an actual loss of all dc power.

- TS Surveillance Requirement 3.4.9 requires the licensee to verify that RCS pressure and temperature and RCS heatup and cooldown rates are less than or equal to 100°F when averaged over a one-hour period. Contrary to this, the licensee failed to verify RCS pressure and temperature, and RCS heatup and cooldown rates were within limits on four separate occasions during a transient on May 26, 2003. This finding affected the Barrier Integrity Cornerstone and was of very low safety significance since it did not represent an actual degradation of a fission product barrier. This was identified in the licensee's CAP as SCR 2003-1169.

- TS 3.4.3 requires eight SRV's to be operable in Modes 1, 2, and 3. Contrary to this, on May 19, 2003, the licensee determined that four SRV's would not have lifted within the required pressure during Cycle 21. This finding affected the Barrier Integrity and Mitigating Systems Cornerstones; however, the finding was not suitable for SDP evaluation, but has been reviewed by NRC management and was determined to be a Green finding of very low safety significance. This was identified in the licensee's CAP as SCR 2003-0946.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Bednar, Emergency Preparedness Manager
C. Blair, Engineer, Licensing
M. Boyce, Corrective Action Program Senior Manager
D. Cook, Senior Manager of Emergency Preparedness
J. Christensen, Acting Nuclear Site Vice President
T. Chard, Radiological Manager
K. Chambliss, Operations Manager
J. Edom, Risk Management
R. Estrada, Performance Analysis Department Manager
M. Faulkner, Security Manager
J. Flaherty, Site Regulatory Liaison
P. Fleming, Risk & Regulatory Affairs Manager
C. Kirkland, Nuclear Information Technology Manager
V. Krueger, Engineer, Engineering Support Division/In-Service Inspection
W. Macecevic, Work Control Manager
L. Schilling, Administrative Services Department Manager
R. Shaw, Senior Reactor Operator
J. Sumpter, Senior Staff Engineer, Licensing
K. Tanner, Shift Supervisor, Radiation Protection
D. Knox, Maintenance Manager
A. Williams, Manager, Engineering Support Division
B. Wulf, Plant Engineering Department Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000298/2003006-001	NCV	Failure to Adequately Model Plant Response in Simulator (Sections 1R11.2)
05000298/2003006-002	NCV	Failure to Follow Procedures During Reactor Scram (Section 1R14)
05000298/2003006-003	NCV	Failure to maintain TS Bases Consistent with the USAR (Section 1R15)
05000298/2003006-004	NCV	Failure to Follow Tagout Procedure (Section 4OA2.1)

Closed

05000298/2001-003-00	LER	Failure to Adequately Revise Procedures Resulted in Inadequate Fire Watches Under Certain Battery/Battery Charger Configurations and an Unanalyzed Condition (Section 4OA3.1)
05000298/2003-003-00	LER	TS Prohibited Operation Due to Safety Relief Valve Test Failures (Section 4OA3.2)
05000298/2003-004-00	LER	Manual Reactor Scram Due to Main Turbine Vibration (Section 4OA3.3)

LIST OF DOCUMENTS REVIEWED

Notification Reports

10230665, 10230828, 10233319, 10235060, 10242698, 10246300, 10234731, 10239351, 10251731, and 10258142

Procedures

Engineering Procedure 3.14, “Temporary Shielding,” Revision 11

Procedure 0.ALARA.2, “ALARA Organization and Management,” Revision 6

Procedure 9.ALARA.1, “Personnel Dosimetry and Occupational Radiation Exposure Program,” Revision 15

Procedure 9.ALARA.4, “Radiation Work Permits,” Revision 3

Procedure 9.ALARA.5, “ALARA Planning and Controls,” Revision 8

Procedure 9.RADOP.3, “Area Posting and Access Control,” Revision 10

CNS Radiation Protection Shop Guide 5, “Hot Spot Reduction Program,” Revision 5

Work Orders

4303040 Corrective maintenance on EDG 1 to replace the digital reference unit
4320231 Corrective maintenance on Hydrogen Valve H2-B-51
4321385 Replacement of the EDG 2 digital reference unit
4322246 Corrective maintenance on Relief Valve RHR-RF-15
4312934 Corrective maintenance on the reactor building ventilation controller
4296891 Preventive maintenance on 4160 v Breaker 1AN on September 25

LIST OF ACRONYMS

ALARA	as low as is reasonably achievable
AOG	augmented off-gas system
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CFR	*Code of Federal Regulations*
CS	core spray
EDG	emergency diesel generator
EOP	emergency operating procedure
FEMA	Federal Emergency Management Agency
HPCI	high pressure coolant injection
LCO	limiting condition for operation
LER	licensee event report
MC	manual chapter
NCV	noncited violation
PCIV	primary containment isolation valve
PI	performance indicator
RCIC	reactor core isolation cooling
RCR	resolve condition report
RHR	residual heat removal
RCS	reactor coolant system
RFP	reactor feedwater pump
RW	radioactive waste
SCR	significant condition report
SDP	Significance Determination Process
SRV	safety relief valve
SW	service water
TS	Technical Specification
USAR	Updated Final Safety Analysis Report