UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

October 28, 2008

Stewart B. Minahan, Chief Nuclear Officer
Nebraska Public Power District
72676 648A Avenue
Brownville, NE 68321

SUBJECT: COOPER NUCLEAR STATION – NRC INTEGRATED INSPECTION REPORT 05000298/2008004; 072000066/2008001

Dear Mr. Minahan:

On September 21, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Cooper Nuclear Station. The enclosed report documents the inspection results, which were discussed on October 9, 2008, with Mr. D. Willis, General Manager of Plant Operations, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, two NRC-identified findings and two self-revealing findings of very low safety significance were identified, all of which involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as noncited violations in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a noncited violation, 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 a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region IV, 612 E. Lamar Blvd., Arlington, TX 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Cooper Nuclear Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Geoffrey B. Miller, Chief
Projects Branch C
Division of Reactor Projects

Docket: 50-298; 72-66
License: DPR-46

Enclosure: NRC Inspection Report 05000298/2008004
w/Attachment: Supplemental Information

Brian O'Grady
Nebraska Public Power District
72676 648A Avenue
Brownville, NE 68321

Gene Mace
Nuclear Asset Manager
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

John C. McClure, Vice President
and General Counsel
Nebraska Public Power District
P.O. Box 499
Columbus, NE 68602-0499

David Van Der Kamp
Licensing Manager
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

Michael J. Linder, Director
Nebraska Department of
Environmental Quality
P.O. Box 98922
Lincoln, NE 68509-8922

Chairman
Nemaha County Board of Commissioners
Nemaha County Courthouse
1824 N Street
Auburn, NE 68305

Julia Schmitt, Manager
Radiation Control Program
Nebraska Health & Human Services
Dept. of Regulation & Licensing
Division of Public Health Assurance
301 Centennial Mall, South
P.O. Box 95007
Lincoln, NE 68509-5007

H. Floyd Gilzow
Deputy Director for Policy
Missouri Department of Natural Resources
P. O. Box 176
Jefferson City, MO 65102-0176

Director, Missouri State Emergency
Management Agency
P.O. Box 116
Jefferson City, MO 65102-0116

Chief, Radiation and Asbestos
Control Section
Kansas Department of Health
and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Melanie Rasmussen, State Liaison Officer/
Radiation Control Program Director
Bureau of Radiological Health
Iowa Department of Public Health
Lucas State Office Building, 5th Floor
321 East 12th Street
Des Moines, IA 50319

John F. McCann, Director, Licensing
Entergy Nuclear Northeast
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601-1813

Keith G. Henke, Planner
Division of Community and Public Health
Office of Emergency Coordination
930 Wildwood, P.O. Box 570
Jefferson City, MO 65102

Art Zaremba
Director of Nuclear Safety Assurance
Nebraska Public Power District
P.O. Box 98
Brownville, NE 68321

Ronald L. McCabe, Chief
Technological Hazards Branch
National Preparedness Division
DHS/FEMA
9221 Ward Parkway
Suite 300
Kansas City, MO 64114-3372

Daniel K. McGhee, State Liaison Officer
Bureau of Radiological Health
Iowa Department of Public Health
Lucas State Office Building, 5th Floor
321 East 12th Street
Des Moines, IA 50319

Ronald D. Asche, President
and Chief Executive Officer
Nebraska Public Power District
1414 15th Street
Columbus, NE 68601

Electronic distribution by RIV:
Regional Administrator (Elmo.Collins@nrc.gov)
DRP Director (Dwight.Chamberlain@nrc.gov)
DRP Deputy Director (Anton.Vegel@nrc.gov)
DRS Director (Roy.Caniano@nrc.gov)
DRS Deputy Director (Troy.Pruett@nrc.gov)
Senior Resident Inspector (Nick.Taylor@nrc.gov)
Resident Inspector (Michael.Chambers@nrc.gov)
Branch Chief, DRP/C (Geoffrey.Miller@nrc.gov)
Senior Project Engineer, DRP/C (Wayne.Walker@nrc.gov)
Public Affairs Officer (Victor.Dricks@nrc.gov)
Team Leader, DRP/TSS (Chuck.Paulk@nrc.gov)
RITS Coordinator (Marisa.Herrera@nrc.gov)
K. S. Fuller (Karla.Fuller@nrc.gov)
OEMail Resource
Senior Enforcement Specialist (Mark.Haire@nrc.gov)

Only inspection reports to the following:
DRS STA (Dale.Powers@nrc.gov)
Mark Cox, OEDO RIV Coordinator (Mark.Cox@nrc.gov)
ROPreports

SUNSI Review Completed: GBM ADAMS: ☒ Yes No Initials: GBM
☒ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☒ Non-Sensitive

R:_REACTORS_CNS\2008\CNS 2008-04RP-NHT.doc ML 083020138

SRI:DRP/C	RI:DRP/C	SPE:DRP/C	C:DRS/EB1	C:DRS/EB2
NHTaylor	MLChambers	WCWalker	RLBywater	GEWerner
/RA/	**/RA/**	**/RA/**	**/RA/**	**/RA/**
10/24/08	10/24/08	10/27/08	10/27/08	10/27/08
C:DRS/OB	C:DRS/PSB	C:DRS/EB2	C:DRP/C	
RELantz	MPShannon	NFO'Keefe	GBMiller	
/RA/	**/RA/**	**/RA/**	**/RA/**	
10/27/08	10/27/08	10/27/08	10/27/08	

OFFICIAL RECORD COPY T= Telephone E= E-mail F = Fax

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-298 ; 72-66
Licenses:	DPR-46
Report:	05000298/2008004; 072000066/2008001
Licensee:	Nebraska Public Power District
Facility:	Cooper Nuclear Station
Location:	72676 648A Avenue Brownville, NE 68321
Dates:	June 22 through September 21, 2008
Inspectors:	N. Taylor, Senior Resident Inspector M. Chambers, Resident Inspector J. Hanna, Senior Resident Inspector, Fort Calhoun Station J. Everett, Senior Materials Inspector P. Elkmann, Senior Emergency Preparedness Inspector
Approved By:	G. Miller, Chief, Project Branch C Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000298/2008004; 06/22/2008 - 09/21/2008; Cooper Nuclear Station. Flood Protection, Outage Activities, Identification and Resolution of Problems, Other Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Four Green findings, all of which were noncited violations, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG 1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified regarding the licensee's failure to follow the requirements of Administrative Procedure 0-CNS-61, "CNS Reactivity Management Program." Specifically, control room operators failed to maintain positive control over reactivity during a plant startup, resulting in an inadvertent increase in reactor power. The licensee entered this issue into their corrective action program as Condition Report CR-CNS-2008-06149.

  The finding is more than minor because it could be reasonably viewed as a precursor to a more significant event. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the resulting transient did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The cause of this finding is related to the human performance cross cutting component of Work Practices because licensee personnel failed to perform an adequate prejob brief and the operators failed to utilize appropriate self or peer checking prior to opening the reactor feed pump discharge valve at low power [H.4(a)] (Section 1R20).

  Cornerstone: Mitigating Systems

- Green. The inspectors identified two examples of a Green NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," regarding the licensee's failure to comply with the requirements of Engineering Procedure 3.3 SAFE, "Safety Assessment." Specifically, licensee personnel failed to identify the potential adverse impact to the station internal flooding analysis of the installation of a temporary air conditioning unit and a crane test load in the reactor building. The licensee entered this issue into their corrective action program as Condition Report CR-CNS-2008-07534.

  The finding is more than minor because it is associated with the design control attribute of the Mitigating Systems Cornerstone, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. Using the Manual Chapter 0609 Phase 1 screening worksheet, the inspectors determined that the finding has very low safety significance because it did not result in the loss of any system safety function. The cause of this finding is related to the human performance cross cutting component of decision making because licensee personnel failed to use conservative assumptions in the decision to make configuration changes on the reactor building floor [H.1(b)] (Section 1R06).

- SLIV. The inspectors identified a Severity Level IV noncited violation of 10 CFR 50.73 (a)(1) regarding the licensee's failure to submit a licensee event report within 60 days after the discovery of an event. Specifically, the inspectors determined that the licensee had failed to report the discovery that one safety relief valve pilot valve had exceeded its Technical Specification allowable lift setpoint for a time greater than allowed by Technical Specifications. The licensee entered this issue into their corrective action program as Condition Report CR-CNS-2008-07535.

  This finding was evaluated using the traditional enforcement process because the failure to accurately report events has the potential to impact the NRC's ability to perform its regulatory function. Consistent with the guidance in Section IV.A.3 and Supplement I, Paragraph D.4, of the NRC Enforcement Policy, this finding was determined to be a Severity Level IV noncited violation (Section 4OA2).

- Green. A self-revealing Green NCV of TS 5.4.1.a was identified regarding the licensee's failure to follow the requirements of General Operating Procedure 2.1.22, "Recovering from a Group Isolation." Specifically, control room operators failed to restore Train B of the standby gas treatment (SGT) system to its standby lineup following a planned group isolation. This error rendered one train of the SGT system inoperable for approximately 12 hours. The licensee entered this issue into their corrective action program as Condition Report CR-CNS-2008-04956.

  The finding is more than minor because it is associated with the configuration control attribute of the Mitigating Systems Cornerstone, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. Using the Manual Chapter 0609 Phase 1 Screening Worksheet, the inspectors determined that the finding has very low safety significance because it did not result in the loss of Train B of SGT for longer than its technical specification allowed outage time. The cause of this finding is related to the human performance cross cutting component of Work Practices because control room operators failed to utilize appropriate self checking techniques when implementing Procedure 2.1.22 [H.4(a)] (Section 4OA5).

REPORT DETAILS

Summary of Plant Status

Cooper Nuclear Station (CNS) began the inspection period at full power on June 22, 2008. On July 25, 2008, CNS implemented an approved power uprate to a new maximum power limit of 2419 megawatts (thermal). The plant operated at full power until operators inserted a manual reactor scram on August 9, 2008 due to a low pressure turbine reheat stop valve failure. CNS resumed full power operations on August 15, 2008, where it remained for the rest of the inspection period.

1. REACTOR SAFETY

Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors selected the systems below based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, updated final safety analysis report (UFSAR), Technical Specification (TS) requirements, Administrative TS, outstanding work orders (WOs), condition reports (CRs), and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP) with the appropriate significance characterization.

The inspectors performed partial system walkdowns of the following risk-significant systems:

- August 20, 2008, Reactor core isolation cooling system
- September 17, 2008, High pressure coolant injection system

These activities constituted two partial system walkdown samples as defined by Inspection Procedure 71111.04-05.

Documents reviewed by the inspector included:

- Surveillance Procedure 6.MISC.503, "31 Day Venting of ECCS and RCIC Injection/Spray Subsytem Piping," Revision 5
- Surveillance Procedure 6.HPCI.103, "HPCI IST and 92 Day Test Mode Surveillance Operation," Revision 33
- System Operating Procedure 2.2.33, "High Pressure Coolant Injection System," Revision 59
- Burns & Roe Drawing 2044, Revision N15
- Clearance Order HPCI-1-HPCI WEEK 0838 OPS HOLD DRAIN

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On September 5, 2008 the inspectors performed a complete system alignment inspection of the control building essential ventilation system verify the functional capability of the system. This system was selected because it an important support system for safety-significant and risk-significant equipment in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved.

Documents reviewed by the inspectors are listed at the end of this report.

These activities constituted one complete system walkdown sample as defined by Inspection Procedure 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05AQ)

.1 Routine Resident Inspector Tours

a. Inspection Scope

The inspectors reviewed the below listed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and had implemented adequate compensatory measures for out-of-service degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed, that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- July 2, 2008, Fire Zone 7A, Control building basement 882' level
- August 5, 2008, Fire Zone 20A, Service water pump room
- August 20, 2008, Fire Zone 1E, High pressure coolant injection room 859' level
- August 20, 2008, Fire Zone 3D, Motor generator set lube oil cooler area 932' level

These activities constituted four quarterly fire protection inspection samples as defined by Inspection Procedure 71111.05AQ-05.

Documents reviewed by the inspectors included:

- CNS Fire Hazards Matrix dated February 28, 2003
- CNS-FP-224, "CNS Fire Pre-plans," Revision 2

b. Findings

No findings of significance were identified.

.2 Annual Inspection

a. Inspection Scope

On September 7, 2008, the inspectors observed a fire brigade drill to evaluate the readiness of licensee personnel to prevent and fight fires, including the following aspects: (1) the number of personnel assigned to the fire brigade, (2) use of protective clothing, (3) use of breathing apparatuses, (4) use of fire procedures and declarations of emergency action levels, (5) command of the fire brigade, (6) implementation of pre-fire strategies and briefs, (7) access routes to the fire and the timeliness of the fire brigade response, (8) establishment of communications, (9) effectiveness of radio communications, (10) placement and use of fire hoses, (11) entry into the fire area, (12) use of fire fighting equipment, (13) searches for fire victims and fire propagation, (14) smoke removal, (15) use of pre-fire plans, (16) adherence to the drill scenario, (17) performance of the post-drill critique, and (18) restoration from the fire drill.

These activities constituted one annual fire brigade observation sample as defined by Inspection Procedure 71111.05AQ-05.

Documents reviewed by the inspectors included:

- Fire Brigade Scenario 25

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

a. Inspection Scope

Semi-annual Internal Flooding

The inspectors reviewed the flood protection features credited for protecting the 903' level of the reactor building from internal flooding sources. The review included: (1) the updated final safety analysis report (UFSAR), the flooding analysis, and plant procedures to assess susceptibilities involving internal flooding; (2) the UFSAR and CAP to determine if the licensee identified and corrected flooding problems; (3) operator actions for coping with flooding to ensure they can reasonably achieve the desired outcomes; and (4) a walk down of the area to verify the adequacy of: (a) equipment seals located below the flood line, (b) floor and wall penetration seals, (c) door seals, (d) common drain lines and sumps, (e) sump pumps, level alarms, and control circuits, and (f) temporary or removable flood barriers.

Documents reviewed by the inspectors are listed at the end of this report.

The inspectors completed one sample as defined by Inspection Procedure 71111.06-05.

b. Findings

Introduction. The inspectors identified two examples of a Green non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” regarding the licensee’s failure to comply with the requirements of Engineering Procedure 3.3SAFE, “Safety Assessment.” Specifically, licensee personnel failed to identify the potential adverse impact to the station internal flooding analysis of the installation of a temporary air conditioning unit and a crane test load in the reactor building.

Description. Engineering Procedure 3.3SAFE, “Safety Assessment,” Revision 11, provides a checklist for engineering personnel to perform nuclear safety assessments for proposed activities. If any of the checklist items are checked “yes” (indicating a potential adverse impact on nuclear safety), then the assessment of the proposed activity must be sent for review to the Station Operations Review Committee and potentially to the General Manager of Plant Operations for approval.

In the first example, the inspectors questioned the licensee about the acceptability of the auxiliary steam tunnel cooling (ASTC) unit that had been placed on the 903’ level of the reactor building. The ASTC unit had become necessary during the previous years due to the declining effectiveness of the installed cooling units in the main steam tunnel. During periods of high external temperatures, the ASTC unit had been brought into the building as a temporary configuration change (TCC) to supplement the installed ventilation system. The ASTC unit consists of (1) a large heat exchanger unit located on the 903’ level of the reactor building to cool the hot air from the steam tunnel, (2) a cooling unit installed in the yard outside the reactor building to create chilled water for the heat exchanger, (3) two six inch diameter hoses that penetrate the secondary containment volume and run across the 903’ level floor to deliver chilled water to the heat exchanger, and (4) large air ducts to deliver the cool air from the heat exchanger to the steam tunnel.

The inspectors noted that the design basis internal flooding calculations for the 903’ level of the reactor building are based on the postulated high energy line break of an eighteen inch main feedwater line in the steam tunnel. This scenario, analyzed in calculation NEDC 91-24, assumes that once the steam tunnel fills with water, the water then spills out through the steam tunnel door, runs across the floor through the north, west and south corridors of the 903’ level, then drains through a removed equipment hatch into the southeast corner of the torus area. The calculation assumed that an 18 foot channel width exists in the north and south corridors, and that a 10.8 foot channel width exists in the west corridor. Based upon these and other input assumptions, the calculation determined maximum flooding depths at different areas of the reactor building. Design Criteria Document 38, “Internal Flooding,” documented that the maximum flood depth on the 903’ level would be 10.8 inches, and that the lowest piece of safety related equipment was at 11 inches. Recognizing the small margin available, inspectors questioned the acceptability of the two six inch diameter chilled water hoses that ran perpendicular to the analyzed water flow path.

Prior to 2007, the ASTC unit was placed in the reactor building as needed through a TCC, the most recent of which was TCC 4441926 approved on August 2, 2005.

Recognizing that the ASTC unit would be necessary in the future, the licensee formalized the configuration change on May 29, 2007 by establishing Maintenance Procedure 7.2.58, “Auxiliary Steam Tunnel Fan Coil Unit Installation and Removal.” In the procedure change request that was completed to justify the new procedure, engineers documented that “the 50.59 and 3.3SAFE for TCC 4441926…remain bounding for the generation of this new procedure to install the units.” The inspectors reviewed the 3.3SAFE that was completed for TCC 4441926 on July 28, 2005. In this assessment, engineers documented that the ASTC unit did not have a potential adverse effect on the internal flooding analysis. The assessment provided a detailed discussion on programs such as secondary containment and fire protection, but provided no rationale for the determination that the internal flooding analysis was not affected.

The inspectors challenged the licensee on this apparent oversight. In response to the inspectors questions, the licensee initiated CR-CNS-2008-06316 and documented that the 3.3SAFE assessment for TCC 4441926 and Procedure 7.2.58 did not fully consider the potential effect of the ASTC unit on internal flooding. In the operability review for this condition report, operations personnel documented that the flow impediment created by the two six inch chill water lines running perpendicular to the flooding flow path could have resulted in an increase in postulated flood levels of as much as two inches upstream of the hoses. The inspectors noted that the limiting component in the original analysis was located downstream of the flow impediment, and was unaffected by this condition. The inspectors determined that this condition, in itself, did not challenge the operability of any safety-related equipment.

In the second example, inspectors noted on September 9, 2008, that the licensee had landed a set of load-test blocks on the 903’ level of the reactor building. The fourteen foot square tower of concrete load-test blocks and cribbing was installed at the southwest corner of the reactor building and represented a significant obstruction in the flow path for the design basis flood. More specifically, the test blocks reduced the width of the 10.8 foot west channel to an effective width of 69 inches. The inspectors challenged the acceptability of this configuration.

The inspectors discovered that the concrete blocks were placed in the reactor building to support load testing of the reactor building crane. The acceptability of this load test had been documented in EE 08-03 on September 8, 2008. The 3.3SAFE assessment checklist that was performed as part of EE 08-03 determined that the impact of the test on the internal flooding analysis was “N/A.” Paragraph 4.6 of EE 08-03 further stated that:

> *“Placing the concrete load-test blocks on cribbing at the R-903’-6” level has no adverse effect on the Flooding Analysis, as the area occupied by the cribbing does not create a new/smaller “choke point” that could impede fluid flow to the South-East Torus Area hatch opening. The existing flow “choke points” remain the bounding condition.”*

This statement in EE 08-03 was not true as observed in the field. Just the opposite was the case; the load-test blocks reduced the 10.8 foot choke-point by approximately one-half of its design. The inspectors questioned the engineers who had performed the analysis, and determined that the potential impact on the flooding analysis was described based on the engineers assumption of a smaller test block (he assumed a 10’ by 14’ load-test block versus the actual block which was 14’ square) and his assumption that the load-test blocks would not be placed near the choke-point of the flooding analysis. Neither of these assumptions was validated by the engineer either prior to or after the test began.

As a result of the inspector's questions, the licensee initiated CR-CNS-2008-06874. In the operability evaluation that was performed for this CR, the licensee removed over-conservatisms from the original flooding calculations and determined that the new postulated flood levels following a high energy line break of the eighteen inch feedwater line would be significantly higher due to the smaller choke-point. The limiting flood height would be 14.52 inches in the northwest corner of the reactor building. This new flood height left less than one-half inch of margin to the top of the flood dam around the ventilation grating atop the northwest quad (overflowing this flood dam could impact the operability of the RHR and suppression pool cooling systems).

Additionally, the inspectors noted that the analyzed configuration of the southeast torus equipment hatch was not correct. Calculation NEDC 91-24 assumed that the water from the design basis flood would flow over the edge of the open hatch like an open waterfall. This assumption allowed the licensee to quantify the rate at which water would be removed from the 903' level of the reactor building. The inspectors noted that the open hatch had been fitted with handrails and a toe board that effectively restrained the flow path into the open hatch to a three-inch gap. This served to reduce the rate at which water could be removed from the reactor building floor. In response to this question from the inspectors, the licensee initiated CR-CNS-2008-06903. In the operability review for this CR, engineers documented that the net impact of this flow impediment could be a one inch rise in postulated flood levels throughout the building. The inspectors learned that the handrails and toe board had been installed in roughly 1986. No information documenting the acceptability of this configuration change could be located by the licensee.

The inspectors noted that both of these unanalyzed conditions (the load-test blocks and the torus hatch toeboard) had been present concurrently for approximately four days. The licensee had not attempted to analyze the combined effect of the two conditions. The inspectors reviewed the potential cumulative affect of these conditions and determined that the worst case flooding impact could have affected the division one RHR pumps but not the division two RHR pumps. As such, the inspectors determined that the combination of these previously unanalyzed conditions could not have resulted in a loss of safety function.

<u>Analysis</u>. The performance deficiency associated with this finding involved the licensee's failure to comply with the requirements of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, licensee personnel failed to comply with Engineering Procedure 3.3SAFE, "Safety Assessment" and identify the potential adverse impact to the station internal flooding analysis of several configuration changes. The finding is more than minor because it is associated with the design control attribute of the Mitigating Systems Cornerstone, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. Using the Manual Chapter 0609 Phase 1 screening worksheet, the inspectors determined that the finding has very low safety significance because it did not result in the loss of any system safety function. The cause of this finding is related to the human performance cross cutting component of decision making

because licensee personnel failed to use conservative assumptions in the decision to make configuration changes on the reactor building floor [H.1 (b)].

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions or drawings. Contrary to this requirement, on July 28, 2005 and September 8, 2008, licensee personnel failed to follow the requirements of Engineering Procedure 3.3SAFE, "Safety Assessment." Specifically, licensee personnel failed to identify the potential adverse impact to the station internal flooding analysis of several configuration changes. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-CNS-2008-07534, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2008004-01, "Failure to Assess Potential Adverse Effects on Internal Flooding Analysis."

1R11 Licensed Operator Requalification Program (71111.11)

Licensee Requalification Examinations

a. Inspection Scope

The inspectors observed testing and training of senior reactor operators and reactor operators to identify deficiencies and discrepancies in the training, to assess operator performance, and to assess the evaluator's critique. The training scenario involved a loss of all control room annunciators and an inbound aircraft threat.

- September 3, 2008, Loss of Annunciators, Aircraft Threat

Documents reviewed by the inspector included:

- Requalification Training Lesson SKL054-01-30

This inspection constitutes one quarterly licensed-operator requalification program sample as defined in Inspection Procedure 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed events such as where ineffective equipment maintenance has resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices

- Identifying and addressing common cause failures

- Scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule (MR)

- Characterizing system reliability issues for performance

- Charging unavailability for performance

- Trending key parameters for condition monitoring

- Ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or reclassification

- Verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the attachment.

The inspectors evaluated degraded performance issues involving the following risk significant systems:

- August 21, 2008, Failure of Z-1 sump pump on May 26, 2008

- August 21, 2008, Failure of Z sump level switches on May 30, 2008

- August 27, 2008, Failure of service water pump A on June 15, 2008

- September 18, 2008, Main lubricating oil high particulate impact on turbine trip block on August 14, 2008

This inspection constitutes four quarterly maintenance effectiveness samples as defined in Inspection Procedure 71111.12-05.

Documents reviewed by the inspector included:

- CR-CNS-2008-04250
- CR-CNS-2008-04262
- CR-CNS-2008-04694
- CR-CNS-2008-06234
- Notification 10592114
- Notification 10591934

b. <u>Findings</u>

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- August 5, 2008, Replacement of A1 spargers
- August 7, 2008, Aggregate risk review (online)
- August 12, 2008, Aggregate risk review during plant startup
- August 26, 2008, Risk controls during DG1 major maintenance window
- September 8, 2008, Risk assessment during reactor building crane load testing

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

These activities constituted five samples as defined by Inspection Procedure 71111.13-05.

Documents reviewed by the inspector are listed at the end of this report.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- June 22, 2008 and July 6, 2008, August 27, 2008, Residual heat removal service water system Train A relief valve lifting

- July 30, 2008, Core spray Pump A low differential pressure

- August 6, 2008, Failure of Sump Z level switches

- August 18, 2008, Main turbine lubricating oil particulate count high out of specification

- September 11, 2008, Reactor building 903' susceptibility to internal flooding

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

This inspection constitutes five samples as defined in Inspection Procedure 71111.15-05.

Documents reviewed by the inspectors are listed at the end of this report.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- July 21, 2008, Temporary blocks under HV-FAN-(SF-R-1A-B)

The inspectors reviewed key affected parameters associated with energy needs, materials/replacement components, timing, heat removal, control signals, equipment protection from hazards, operations, flow paths, pressure boundary, ventilation boundary, structural, process medium properties, licensing basis, and failure modes for the modification listed below. The inspectors verified that: (1) modification preparation, staging, and implementation did not impair emergency/abnormal operating procedure actions, key safety functions, or operator response to loss of key safety functions; (2) postmodification testing will maintain the plant in a safe configuration during testing by verifying that unintended system interactions will not occur, SSC performance characteristics still meet the design basis, the appropriateness of modification design assumptions, and the modification test acceptance criteria will be met; and (3) licensee personnel identified and implemented appropriate corrective actions associated with permanent plant modifications.

This inspection constituted one sample for temporary modifications as defined in Inspection Procedure 71111.18-05.

Documents reviewed by inspectors included:

- Temporary Configuration Change 4493640

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the following postmaintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- July 23, 2008, Average power range monitor modification post work test
- July 25, 2008, Thermal power optimization startup test
- August 12, 2008, Electrical motor testing on service water booster Pump B
- August 27, 2008, Replacement of relay PC-REL-ISO6BX on July 22, 2008
- August 27, 2008, Seal weld on RF-V-747 pipe plug during forced outage
- September 16, 2008, High pressure coolant injection retest following planned maintenance

These activities were selected based upon the SSCs ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed, testing was adequate for the maintenance performed, acceptance criteria were clear and demonstrated operational readiness, test instrumentation was appropriate, tests were performed as written in accordance with properly reviewed and approved procedures, equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion), and test documentation was properly evaluated. The inspectors evaluated the activities against TS, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed during the inspection are listed in the attachment.

This inspection constitutes six samples as defined in Inspection Procedure 71111.19-05.

Documents reviewed by inspectors are listed at the end of this report.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Forced Outage Activities

a. Inspection Scope

During a four-day forced outage beginning on August 9, 2008, the inspectors reviewed the licensee's outage work scope, the outage risk profile, and verified that key shutdown safety functions, such as power availability and decay heat removal, were not challenged by the outage work scope. The inspectors monitored significant activities including reactor shutdown and startup, forced cooldown, and control rod scram timing testing.

The inspectors completed one sample as defined in Inspection Procedure 71111.20-05.

Documents reviewed by inspectors included:

- General Operating Procedure 2.1.1, "Startup Procedure," Revision 146
- General Operating Procedure 2.1.1.1, "Plant Startup Review and Authorization," Revision 20
- General Operating Procedure 2.1.1.2, "Technical Specification Pre-Startup Checks," Revision 32

b. Findings

Introduction. A self revealing Green noncited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified regarding the licensee's failure to follow the requirements of Administrative Procedure 0-CNS-61, "CNS Reactivity Management Program." Specifically, control room operators failed to maintain positive control over reactivity during a plant startup, resulting an inadvertent increase in reactor power.

Description. On August 11, 2008, control room operators were in the progress of completing a plant startup following a forced outage. Reactor pressure was approximately 350 psig and the reactor vessel level control system was controlling the six inch diameter startup flow control valve to maintain reactor vessel level within the prescribed control band. At the beginning of the event, reactor vessel level was 35 inches and reactor power was approximately 3% on all average power range monitors.

As part of the procedure for power ascension, control room operators were preparing reactor feed Pump A for startup. The feed pump discharge valve had been tagged shut during the forced outage as an isolation boundary for downstream work. As part of the tag clearance and valve lineup, control room operators needed to move the valve in the open direction far enough to verify that it was not stuck in the shut seat. The panel operator who was assigned this task had performed a cursory pre-job brief with the control room supervisor which discussed only the process of clearing the tags. The brief did not address the potential for the eighteen inch diameter feed pump discharge line to add inventory or positive reactivity. Additionally, neither the reactor operator nor the assigned reactivity manager, who was in the control room at the time, were notified of this upcoming evolution that had the potential to add reactivity to the core.

When the panel operator was ready to test the feed pump discharge valve in the open direction, he asked the reactor operator to perform a peer check for him. The reactor operator recognized the potential for a large reactivity addition, and instructed the panel operator not to open the valve all the way. Subsequent to this conversation, the panel operator placed the control switch for the feed pump discharge valve in the open position and held it there for approximately 5 seconds. After releasing the switch, the reactor operator instructed him to shut the valve, which he then did. In the 24 seconds that the valve was off its shut seat, reactor vessel level rose approximately 13 inches. During the transient, the Reactor Water High Level alarm came in at its setpoint of 42.5 inches, reactor power doubled from 3% to 6% on all average power range meters, and vessel level crested at approximately 48 inches. This peak level was just short of the 50 inch procedural requirement to insert a manual scram. With the feed pump discharge valve now shut, the reactor vessel level control system restored vessel level to approximately 35 inches within fifteen minutes of the beginning of the transient, and reactor power returned to its previous value of 3%. The Reactor Water High Level alarm was in for approximately two minutes during the transient.

<u>Analysis</u>. The performance deficiency associated with this finding involved the licensee's failure to comply with the requirements of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, control room operators failed follow the requirements of Procedure 0-CNS-61, "CNS Reactivity Management Program," to maintain positive control over reactivity during a plant startup, resulting an inadvertent increase in reactor power. The finding is more than minor because it could be reasonably viewed as a precursor to a more significant event. Using the Manual Chapter 0609, "Significance Determination Process," Phase 1 Worksheet, the finding is determined to have very low safety significance because the resulting transient did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. The cause of this finding is related to the human performance cross cutting component of Work Practices because licensee personnel failed to perform an adequate pre-job brief and the operators failed to utilize appropriate self or peer checking prior to opening the reactor feed pump discharge valve at low power [H.4(a)].

<u>Enforcement</u>. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions or drawings. Administrative Procedure 0-CNS-61, "CNS Reactivity Management Program," Revision 17, requires that control room operators maintain positive control over reactivity during all reactivity manipulations. Contrary to this requirement, on August 11, 2008, control room operators misoperated a reactor feed pump discharge valve, inserting a large volume of cold water into the reactor and resulting in a doubling of reactor power. Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-CNS-2008-06149, this violation is being treated as an NCV consistent with Section VI.A of the

Enforcement Policy: NCV 05000298/2008004-02, "Operator Error Results in Uncontrolled Reactivity Addition."

1R22 Surveillance Testing (71111.22)

.1 Routine Surveillance Testing

a. Inspection Scope

The inspectors observed in-plant activities and reviewed procedures and associated records to determine whether: any preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; plant equipment calibration was correct, accurate, and properly documented; as left setpoints were within required ranges; the calibration frequency was in accordance with TS, the UFSAR, procedures, and applicable commitments; measuring and test equipment calibration was current; test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied; test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used; test data and results were accurate, complete, within limits, and valid; test equipment was removed after testing; where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable; where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure; where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished; prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test; equipment was returned to a position or status required to support the performance of the safety functions; and all problems identified during the testing were appropriately documented and dispositioned in the CAP.

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- August 10, 2008, Plant startup and heatup
- August 12, 2008, Service water booster pump IST on July 24, 2008
- August 20, 2008, Drywell floor drain sump flow measuring test
- August 20, 2008, 31 day venting of ECCS and RCIC piping

This inspection constitutes four surveillance testing samples as defined in Inspection Procedure 71111.22-05.

Documents reviewed by the inspectors are listed at the end of this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors performed an in-office review of Revision 37 to Emergency Plan Implementing Procedure 5.7.1, “Emergency Classification,” submitted July 16, 2008, and its associated 50.54(q) review document. This revision changed the description in emergency action levels of the top of active fuel from 0 inches fuel zone, to -158 inches instrument zero.

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 standards in 10 CFR 50.47(b) to determine if the revision adequately implemented the requirements of 10 CFR 50.54(q). This review was not documented in a safety evaluation report and did not constitute an approval of the licensee’s changes, therefore these revisions are subject to future inspection.

The inspectors completed one sample during the inspection as defined in Inspection Procedure 71114.04-05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on July 9, 2008, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the attachment.

This inspection constitutes one sample as defined in Inspection Procedure 71114.06-05.

Documents reviewed by the inspectors included:

- CNS Operations Manual Emergency Plan Implementing Procedure 5.7.1, "Emergency Classification," Revision 38
- Scenario package for drill on July 9, 2008
- July 9, 2008 Team 4 Drill Critique Report, dated July 30, 2008

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA2 Identification and Resolution of Problems (71152)

.1 Daily CAP Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily CR packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection

a. Inspection Scope

In order to verify that the licensee has taken corrective actions commensurate with the significance of issues, the inspectors performed an in-depth review of information from the selected CR samples identified below. Attributes considered during the in-depth review of licensee actions associated with individual issues included: accurate identification of the problem in a timely manner; evaluation of operability/reportability issues; consideration of extent of condition, generic implication, common cause, and previous occurrences; classification and prioritization of problem resolution commensurate with its safety significance; identification of root and contributing causes of the problem; identification of corrective actions focused to correct the problem; and completion of corrective actions in a timely manner commensurate with the safety significance of the issue.

- July 11, 2008, As Found Main Steam SRV Testing Results
- July 24, 2008, In-depth review of operator workarounds
- August 27, 2008, Slow start of emergency diesel generator #1

This inspection constitutes completion of three in-depth problem identification and resolution samples as defined in Inspection Procedure 71152-05.

Documents reviewed by the inspectors are listed at the end of this report.

b. Findings

Introduction. The inspectors identified a Severity Level IV noncited violation of 10 CFR 50.73 (a)(1) regarding the licensee's failure to submit a licensee event report (LER) within 60 days after the discovery of an event. Specifically, the inspectors determined that the licensee had failed to report the discovery that one safety relief valve (SRV) pilot valve had exceeded its Technical Specification (TS) allowable lift setpoint for a time greater than allowed by TS.

Description. On July 11, 2008, the licensee initiated CR-CNS-2008-05389 to document the results of main steam SRV testing on the SRV pilot valves that had been removed during the RE24 refueling outage in April 2008. The CR reported that one of the eight valves tested (SRV pilot valve number 1244) had lifted at 1165 psig, in excess of the TS maximum allowed lift setting of 1133 psig. The CR went on to report that subsequent lifts were performed within the TS allowable range of 1100 +/- 33 psig, and that "this is a classic symptom of pilot disc-to-seat corrosion bonding."

The inspectors reviewed TS 3.4.3 and SR 3.4.3.1 and determined that all eight SRVs are required to be operable in Modes 1,2 and 3, and that the safety function lift setpoint for this valve is 1100 +/- 33 psig. A review of the TS Bases for TS 3.4.3 noted that:

> *"Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded."*

Cooper previously reported SRV pilot valve failures following both of the last two refueling outages. LER 2005-002 reported that during testing following refueling outage RE22 three of eight SRV pilots tested had exceeded their TS allowable lift set points due to corrosion bonding. LER 2007-002 reported a single SRV failure during testing following refueling outage RE23, also due to corrosion bonding.

Corrosion bonding occurs when an SRV pilot disc-seat interface oxidizes, sticking the two parts together. In the apparent cause report performed for CR-CNS-2008-05389, the licensee described this failure mode as follows:

> *"Corrosion bonding is a crevice corrosion phenomenon that occurs to metals that are highly polished and placed in a wetted solution in close proximity to each other….Normally, an oxide bridge will form between the pilot disc and the seat during high temperature service."*

The net effect is that more force is required to separate the disc and seat, effectively raising the setpoint of the SRV until the oxidation layer is broken. Additionally, the nature of this failure mode is that it develops with time at temperature. Based on this understanding of the failure mode, the inspectors determined that SRV pilot 1244 had become inoperable sometime during the previous eighteen-month refueling cycle. The inspectors noted that action statement A of TS 3.4.3 requires that if one or more SRVs is inoperable, the plant must be transitioned to Mode 3 within twelve hours and Mode 4 within thirty-six hours. The inspectors determined that it was highly unlikely that the SRV had become inoperable during that last 12 hours of the eighteen-month cycle. As such, the inspectors determined that the plant had been in a condition not allowed by Technical Specifications. More specifically, SRV pilot 1244 had been inoperable for more than 12 hours without the plant being transitioned to Mode 3.

The inspectors noted that 10 CFR 50.73(a)(2)(i)(B) requires an LER to be submitted for "Any operation or condition prohibited by the plant's Technical Specifications." 10 CFR 50.73 (a)(1) requires that LERs be submitted within 60 days after the discovery of the event. The inspectors noted that more than 60 days had passed from discovery of the event on July 11, 2008 and that no LER had been submitted.

The inspectors reviewed the corrective actions taken by the licensee for the continuing trend of SRV failures, including installation of Stellite-21 pilot discs. The inspectors determined that the actions taken by the licensee for the technical issue were consistent with those proposed by the industry to correct SRV setpoint drift issues.

Analysis. The performance deficiency associated with this finding involves the licensee's failure to comply with the requirements of 10 CFR 50.73 (a)(2)(i)(B). This finding was evaluated using the traditional enforcement process because the failure to accurately report events has the potential to impact the NRC's ability to perform its regulatory function. Consistent with the guidance in Section IV.A.3 and Supplement I, Paragraph D.4, of the NRC Enforcement Policy, this finding was determined to be a Severity Level IV (SL IV) noncited violation.

Enforcement. 10 CFR 50.73 (a)(2)(i)(B) requires that any condition or operation prohibited by TS be reported in an LER. Contrary to this requirement, on July 14, 2008, the licensee determined that an LER was not required following the discovery that that one SRV had exceeded its TS allowable lift setting tolerance for a time greater than allowed by TS. However, because the failure to report is a SL IV violation and has been entered into the licensees CAP as CR-CNS-2008-07535, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000298/2008004-03, "Failure to Report Safety Relief Valve Test Results Above Technical Specification Allowed Setpoint."

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors performed observations of security force personnel and activities to ensure that the activities were consistent with Cooper Nuclear Station security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Onsite Fabrication of Components and Construction of an Independent Spent Fuel Storage Installation (ISFSI) (60853)

a. Inspection Scope

The inspector observed the concrete pouring of the 265 foot by 42 foot ISFSI pad which will be used to store the Cooper Nuclear Station spent fuel in dry canisters. Cooper will utilize the Transnuclear horizontal storage system under general license 72-1004. The concrete pad did not provide a safety related or an important to safety function and was designed to commercial grade installation requirements. Pylons, 18 inches in diameter, extending 75 feet down to bedrock supported the 3 foot thick pad. Quality control samples were taken throughout the pad pouring activities to verify slump and air content. Close observation was provided by the construction manager of the concrete placement activities and quick decisions to terminate placement of the content of several trucks were made when concrete consistency appeared to contain too much water such that slump requirements would not be met. Minimum break strength test requirements were established at 5,000 pounds/square inch for the 28 day break tests. Tests had been conducted on the proposed concrete mix by the licensee prior to the ISFSI pad construction and demonstrated an average of 6,154 pounds/square inch break value for the 28 day break tests. The inspector reviewed the following documents as part of this inspection:

- General Testing Laboratory Results on LF-5000 Mix Test dated June 11, 2008
- Design Package Number CED 6024681 (147604.51.1210) ISFSI Pad/Apron Design, Revision 0

b. Findings

No findings of significance were identified.

.3 Failure to Restore Standby Gas System to Standby Lineup

a. Inspection Scope

The inspectors reviewed the licensee's actions in response to a misalignment of the standby gas treatment system on June 24, 2008. The inspectors reviewed the licensee's control of the evolution through work control documents, established procedures and operating logs. The followup inspection focused specifically on the apparent cause and corrective actions taken as a result of this event.

Documents reviewed by inspectors included:

- CR-CNS-2008-04956
- General Operating Procedure 2.1.22, "Recovering from a Group Isolation," Revision 51
- System Procedure 2.2.73, "Standby Gas Treatment System," Revision 47
- Administrative Procedure O-HU-TOOLS, "Human Performance Tools," Revision 7

b. Findings

Introduction. A self revealing Green noncited violation of TS 5.4.1.a was identified regarding the licensee's failure to follow the requirements of General Operating Procedure 2.1.22, "Recovering from a Group Isolation." Specifically, control room operators failed to restore Train B of the standby gas treatment (SGT) system to its standby lineup following a planned group isolation. This error rendered one train of the SGT system inoperable for approximately 12 hours.

Description. On June 24, 2008, control room operators were preparing for a planned power supply transfer of the reactor protection system (RPS) Train B power panel. The transfer was necessary to facilitate the replacement of a pair of faulty electronic protection system assembly circuit breakers in the normal power supply to the RPS power panel. Operators properly recognized that the transfer of the RPS power panel electrical supplies would cause a group isolation signal to occur. The preparation for this activity required manipulation of several safety systems, including the SGT system.

The SGT system includes two redundant trains, each of which contains a fan. Each of these two fans is fitted with a control switch that can be positioned in either RUN, AUTO, STDBY, or OFF. In the AUTO position, each fan will start in response to a Group 6 isolation signal (which can be caused by such signals as a high drywell pressure or low reactor vessel level). In the STANDBY position, each fan will start on (1) a low SGT flow signal and a Group 6 isolation signal present, or (2) a low SGT flow signal and the other train's fan control switch in the RUN position.

During the planned transfer of the RPS power panel to its alternate power supply, a Group 6 isolation signal was received and both trains of SGT auto-started as expected. Control room operators followed the requirements of General Operating Procedure 2.1.22, "Recovering From A Group Isolation," which requires them to "align SGT per Procedure 2.2.73 within 1 hour of receiving Group 6." Control room operators took the required actions of System procedure 2.2.73, "Standby Gas Treatment System," which directed them to place the preferred SGT fan (in this case Fan A) in RUN and the other fan in STDBY (in this case Fan B).

Control room operators continued with the restoration from the Group 6 isolation. After the normal reactor building ventilation system had been restored to operation, operators removed SGT Fan A from service as required by taking its control switch to OFF and then to AUTO. The final step of the restoration directed operators to refer to several operating procedures, including Procedure 2.2.73, to "return affected systems to normal operating or standby status." Control room operators failed to complete this step. As a result, the Fan B control switch was left in the STDBY position at the end of the restoration at approximately 0850 on June 24, 2008.

Later that day, at time 2102, SGT Train A was started in preparation for shifting the RPS power supplies back to their normal source. When the control switch for Fan A was placed in the RUN position, both Trains A and B of SGT started. The start of Train B was unexpected and led operators to the discovery that the Fan B control switch had been in the wrong position (STDBY versus AUTO) for the preceding twelve hours. The net effect of this mispositioned switch was that for the previous twelve hours, Train B would not have auto-started in response to a Group 6 isolation signal. This condition made SGT Train B inoperable for the affected twelve hour period. The operability of Train A was unaffected by this error, and as such no loss of safety function occurred.

The operator who completed the restoration steps of Procedure 2.1.22 failed to complete the last step of the procedure due to an assumption that Procedure 2.1.22 adequately restored the SGT system to a standby lineup without that step. In making this assumption, the operator failed to use CNS standards for self-checking. Specifically, Administrative Procedure O-HU-TOOLS, "Human Performance Tools," Revision 7, warns operators that "self-checking must be performed against controlled information sources….including actual procedure requirements (vice "off the top-of-the-head" information)." By making an assumption about what the procedure accomplished, the operator missed the procedural step that would have restored the system to its proper lineup.

Analysis. The performance deficiency associated with this finding involved the licensee's failure to comply with the requirements General Operating Procedure 2.1.22, "Recovering from a Group Isolation." Specifically, control room operators failed to restore Train B of the standby gas treatment system to its standby lineup following planned group isolation. The finding is more than minor because it is associated with the configuration control attribute of the Mitigating Systems Cornerstone, and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. Using the Manual Chapter 0609 Phase 1 Screening Worksheet, the inspectors determined that the finding has very low safety significance because it did not result in the loss of SGT Train B for longer than its Technical Specification allowed outage time. The cause of this finding is related to the human performance cross cutting component of work practices because control room operators failed to utilize appropriate self checking techniques when implementing Procedure 2.1.22 [H.4(a)].

Enforcement. TS 5.4.1.a requires that written procedures be established, implemented, and maintained covering the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, section 4.u, requires that operation of the standby gas treatment system be conducted in accordance with written procedures. Contrary to this requirement, on June 24, 2008, control room operators failed to restore standby gas treatment system Train B to a standby lineup as required by General Operating Procedure 2.1.22, "Recovering from a Group Isolation." Because the finding is of very low safety significance and has been entered into the licensee's CAP as CR-CNS-2008-04956, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy: NCV 05000298/2008004-04, "Failure to Restore Standby Gas System to Standby Lineup."

4OA6 Management Meetings

. Exit Meeting Summary

On August 8, 2008, regional inspectors conducted a telephonic exit meeting to present the results of the in-office inspection of the licensee's changes to their emergency plan to Mr. J. Austin, Emergency Planning Manager, who acknowledged the findings.

On October 9, 2008, the resident inspectors presented the quarterly inspection results to Mr. D. Willis, General Manager of Plant Operations and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed no proprietary information was examined during the inspection.

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee

J. Austin, Emergency Planner Manager
D. Beauchaine, Assistant ISFSI Project Manager
M. Bennett, Licensing Engineer
V. Bhardwaj, Manager, Engineering Support
M. Boyce, Director of Projects
D. Buman, System Engineering-Manager
M. Colomb, General Manager of Plant Operations
P. Donahue, ISFSI Project Manager
S. Domikaitis, Mechanical Design-Supervisor
J. Ehlers, System Engineer-SED
R. Estrada, Manager-Corrective Action
J. Flaherty, Senior Staff Licensing Engineer
G. Gardner, Civil Design Supervisor-Design Engineering
G. Horn, Engineering Specialist-Design Engineering
G. Kline, Director of Engineering
J. Maddox, Engineer
D. Madsen, Licensing Engineer
M. Metzger, System Engineer-SED
E. McCutchen, Senior Licensing Engineer
D. Sealock, Manager, Training
T. Stevens, Manager-Design Engineering
D. VanDerKamp, Manager-Licensing
R. Wenzl, Senior Project Manager
D. Werner, Operations Training-Supervisor
K. Woods, Engineer

Black & Veach

J. Draper, Design Engineer
M. Lee, Design Engineer

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000298/2008004-01	NCV	Failure to Assess Potential Adverse Effects on Internal Flooding Analysis (Section 1R06)
05000298/2008004-02	NCV	Operator Error Results in Uncontrolled Reactivity Addition (Section 1R20)
05000298/2008004-03	SLIV	Failure to Report Safety Relief Valve Test Results Above Technical Specification Allowed Setpoint (Section 4OA2)
05000298/2008004-04	NCV	Failure to Restore Standby Gas System to Standby Lineup (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Section 1R04: Equipment Alignment

NEDC 88-299A, "Review of S&L Calc. No COOLC-01," Revision 6

Operations System Training Manual, Volume 4, "Ops Heating, Ventilation and Air Conditioning,"Revision 18

Burns and Roe Drawing 2018, "Turbine Generator Bldg and Control Bldg Heating and Ventilating," Revision N36

Drawing 3295-VD-1, "Volume Damper Details," Revision 1

Cooper Nuclear Station System Health Report for Control Building Ventilation dated June 2008

List of Control Building Condition Reports from January 1, 2003 to September 3, 2008

System Operating Procedure 2.2.38, "HVAC Control Building," Revision 31

System Operating Procedure 2.2.38A, "HVAC Control Building System Component Checklist," Revision 5

System Operating Procedure 2.2.38.1, "Portable Ventilation System," Revision 4

System Operating Procedure 2.2.38.2, "Portable Heating System," Revision 13

USAR Section 10.0, “Heating Ventilation and Air Conditioning Systems”

Section 1R06: Flood Protection

Engineering Procedure 3.3SAFE, “Safety Assessment,” Revision 11

Design Criteria Document 38, “Internal Flooding,” dated November 8, 2006

NEDC 91-24, “Maximum Flooding in NE Quad (HELB),” dated June 12, 1991

Maintenance Procedure 7.2.58, “Auxiliary Steam Tunnel Fan Coil Unit Installation and Removal,” Revisions 0, 1, 2, and 3

Temporary Configuration Change 4441926

CR-CNS-2008-06316

CR-CNS-2008-06877

CR-CNS-2008-06903

Engineering Evaluation 08-003, “Reactor Building Crane Load Test,” Revision 0

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

WO 4627622

WO 4636266

WO 4551940

System Operating Procedure 2.2.3.1, “Travelling Screen, Screenwash, and Sparger System,” Revision 71

CR-CNS-2008-06048

Operations Department Instruction 11, “Aggregate Risk Assessment,” dated April 29, 2008

Aggregate Risk Review Analysis results (various)

Administrative Procedure 0.49, “Schedule Risk Assessment,” Revision 21

Section 1R15: Operability Evaluations

CR-CNS-2008-04846

CR-CNS-2008-05239

CR-CNS-2008-05240

CR-CNS-2008-04262

CR-CNS-2008-05860

CR-CNS-2008-06234

CR-CNS-2008-06316

ENN-OP-104, “Operability Determinations,” Revision 2

Surveillance Procedure 6.SUMP.101, “Z Sump and Air Ejector Holdup Line Drain Operability Test (IST),” Revision 20

Core spray pump A oil quality reports from January 5, 2004 through February 11, 2008

Section 1R19: Postmaintenance Testing

Special Procedure SP07-002, “Thermal Power Optimization Startup Test,” Revision 2

WO 4632310

WO 4649611

WO 4582369

Part Evaluation 4638396

Surveillance Procedure 6.1APRM.305, “APRM System Channel Calibration (DIV 1),” Revision 32

Surveillance Procedure 6.HPCI.103, “HPCI IST and 92 Day Test Mode Surveillance Operation,” Revision 33

Section 1R22: Surveillance Testing

Surveillance Procedure 6.MISC.503, “31 Day Venting of ECCS and RCIC Injection/Spray Subsystem Piping,” Revision 5

Surveillance Procedure 6.RCS.601, “Technical Specification Monitoring of RCS

Heatup/Cooldown Rate,” Revision 14

Surveillance Procedure 6.2SWBP.101, “RHR Service Water Booster Pump Flow Test and Valve

Operability Test (DVI 2),” Revision 14

Surveillance Procedure 6.DWLD.301, “Drywell Floor Drain Sump Flow Measuring System Functional Test,” Revision 4

WO 4602197

WO 4581573

WO 4582023

CR-CNS-2008-06378

Section 4OA2: Identification and Resolution of Problems

CR-CNS-2008-01960

CR-CNS-2008-05758

Conduct of Operations Procedure 2.0.12, “Operator Challenges,” Revision 7

CR-CNS-2008-05389

Licensing Department Guideline LDG-13, “Licensing Department Review of PCRS Condition Reports,” Revision 8

Administrative Procedure 0.42.2, “Licensee Event Reporting,” Revision 9

LER 2005-002-00, “Technical Specification Prohibited Operation Due to Safety Relief Valve Test Failures,” July 11, 2005

LER 2007-002-00, “Technical Specification Prohibited Operation Due to Safety Relief Valve Test Failure,” April 30, 2007

LIST OF ACRONYMS USED

ADAMS	Agency Documents Access & Management System
APRM	average power range monitor
ASTC	auxiliary steam tunnel cooling
CAP	corrective action program
CFR	Code of Federal Regulations
CNS	Cooper Nuclear Station
CR	condition report
ERO	emergency response operations
HPCI	high pressure coolant injection
IR	inspection Report
ISFSI	Independent Spent Fuel Storage Installation
MR	maintenance rule
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
RCIC	reactor core isolation cooling
RHR	residual heat removal
RPS	reactor protection system
SSC	systems, structures, and components
SGT	standby gas treatment
TCC	temporary configuration change
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	work order