UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

August 5, 2009

Mr. Michael D. Wadley
Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2009003; 05000306/2009003

Dear Mr. Wadley:

On June 30, 2009, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on July 9, 2009, with you 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, one NRC-identified and six self-revealing findings of very low safety significance were identified. Five of these findings 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 Non-Cited Violations (NCVs) in accordance with Section VI.A.1 of the NRC Enforcement Policy. Additionally, three licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity 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 a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant. The information that you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be 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), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket Nos. 50-282; 50-306; 72-010
License Nos. DPR-42; DPR-60; SNM-2506

Enclosure: Inspection Report 05000282/2009003; 05000306/2009003
w/Attachment: Supplemental Information

cc w/encl: D. Koehl, Chief Nuclear Officer
G. Salamon, Regulatory Affairs Manager
P. Glass, Assistant General Counsel
Nuclear Asset Manager
J. Stine, State Liaison Officer, Minnesota Department of Health
Tribal Council, Prairie Island Indian Community
Administrator, Goodhue County Courthouse
Commissioner, Minnesota Department
of Commerce
Manager, Environmental Protection Division
Office of the Attorney General of Minnesota
Emergency Preparedness Coordinator, Dakota
County Law Enforcement Center

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Emergency Preparedness Coordinator, Dakota County Law Enforcement Center

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Letter to M. Wadley from J. Giessner dated August 5, 2009

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2009003; 05000306/2009003

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REGION III

Docket Nos:	50-282; 50-306; 72-010
License Nos:	DPR-42; DPR-60; SNM-2506
Report No:	05000282/2009003; 05000306/2009003
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	April 1 through June 30, 2009
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector D. Betancourt, Reactor Engineer R. Jones, Reactor Engineer J. Neurauter, Engineering Inspector M. Phalen, Senior Radiation Protection Inspector
Approved by:	J. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS 1
REPORT DETAILS 6

Summary of Plant Status 6

1. REACTOR SAFETY 6

1R01 Adverse Weather Protection (71111.01) 6
1R04 Equipment Alignment (71111.04) 8
1R05 Fire Protection (71111.05) 9
1R06 Flooding (71111.06) 10
1R11 Licensed Operator Requalification Program (71111.11) 12
1R12 Maintenance Effectiveness (71111.12) 12
1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13) 13
1R15 Operability Evaluations (71111.15) 14
1R19 Post-Maintenance Testing (71111.19) 18
1R20 Outage Activities (71111.20) 20
1R22 Surveillance Testing (71111.22) 21
1EP6 Drill Evaluation (71114.06) 22

2. RADIATION SAFETY 23

2OS1 Access Control to Radiologically Significant Areas (71121.01) 23
2OS2 As-Low-As-Reasonably-Achievable Planning And Controls (71121.02) 27

4. OTHER ACTIVITIES 28

4OA1 Performance Indicator Verification (71151) 28
4OA2 Identification and Resolution of Problems (71152) 30
4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153) 38
4OA5 Other Activities 47
4OA6 Management Meetings 48
4OA7 Licensee-Identified Violations 48

SUPPLEMENTAL INFORMATION 1

Key Points of Contact 1
List of Items Opened, Closed and Discussed 1

List of Documents Reviewed 3

List of Acronyms Used 12

SUMMARY OF FINDINGS

IR 05000282/2009003; 05000306/2009003; 04/01/2009 – 06/30/009; Prairie Island Nuclear Generating Plant, Units 1 and 2; Operability Evaluations, Post-Maintenance Testing and Event Followup.

This report covers a 3-month period of inspection by resident and regional inspectors and an announced radiation protection baseline inspection by a regional inspector. Seven Green findings were identified. Five of these findings were considered Non-Cited Violations of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Cross-cutting aspects were determined using Inspection Manual Chapter 0305, "Operating Reactor Assessment Program." Findings for which the SDP 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-Revealed Findings

Cornerstone: Initiating Events

- Green. A self-revealed finding of very low safety significance was identified on May 9, 2009, due to operations personnel failing to ensure that procedures used to test the Unit 2 turbine stop valves provided adequate guidance regarding the valve position limiter setting. The failure to ensure that adequate guidance was provided prior to performing the turbine stop valve test resulted in a reactor coolant system transient and a seven percent reduction in reactor power. Corrective actions for this issue included revising the test procedure to ensure that guidance regarding the valve position limiter setting was adequate, providing additional training on the digital electro-hydraulic control system to operations personnel, and re-enforcing the human performance fundamentals.

  The inspectors determined that this finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone. In addition, the finding affected the cornerstone objective of limiting the likelihood of events that upset plant stability during power operations. The inspectors concluded that this finding was of very low safety significance because it did not result in exceeding the Technical Specifications limit on reactor coolant system leakage, did not result in a total loss of safety function of a mitigating system, did not contribute to both the likelihood of a reactor trip and that mitigating systems equipment would not be available, and it did not increase the likelihood of a fire or flood. The inspectors determined that this finding was cross-cutting in the Human Performance, Decision Making area because operations personnel failed to use conservative assumptions in deciding how the valve position limiter operated. In addition, operations personnel failed to demonstrate that their proposed actions regarding the valve position limiter setting was safe (by reviewing design basis or training documents and/or requesting assistance from additional personnel) prior to performing the test (H.1(b)). No violation of NRC requirements was identified because the turbine stop valves are non-safety related. (Section 4OA3.5)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V on April 28, 2009, for failure to have adequate procedures to control compensatory actions for degraded/non-conforming conditions. Specifically the failure to implement positive controls for the Unit 2 roll-up door as a compensatory measure for an operability determination invalidated the determination. The door was discovered less than the 18"-open requirement which supported the flooding evaluation. Corrective actions for this issue included opening the Unit 2 turbine building roll-up door to greater than 18 inches open, implementing positive configuration controls for the compensatory measures, and revising the operability determination procedure to require the implementation of positive controls.

  The inspectors determined that this finding was more than minor because if left uncorrected the failure to properly control compensatory measures could result in rendering equipment inoperable (a more significant safety concern). This finding was of very low safety significance because it was not a design or qualification deficiency, did not result in a loss of system safety function or the loss of a single train for greater than the Technical Specification allowed outage time, and it did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event since the roll-up door was 14 inches open and would have provided some mitigation following an internal flooding event. The inspectors determined that this issue was cross-cutting in the Human Performance, Resources area because the licensee failed to ensure that the operability determination procedure was adequate in regards to the control of compensatory measures (H.2(c)). (Section 1R15.1b(1))

- Green. A self-revealed finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V were identified on March 19, 2009, due to the failure to have adequate procedures to control maintenance activities to ensure that plant equipment was not unnecessarily challenged. Specifically, the failure to adequately control maintenance on the 12 diesel-driven cooling water pump resulted in the unplanned automatic start of the 121 motor-driven cooling water pump during post-maintenance testing activities. Corrective actions for this issue included adding instructions to the post-maintenance testing procedure to ensure that it properly referenced the procedure used to realign the 121 motor-driven cooling water pump. The licensee planned to complete a review of safety-related preventive maintenance procedures to ensure that proper procedure referencing and branching was utilized. Lastly, the licensee will add additional staff to assist with the procedure upgrade program and the coordination of preventive maintenance activities.

  The inspectors determined that this finding was more than minor because if left uncorrected the failure to properly control maintenance activities could become a more significant safety concern. In addition, the inspectors determined that the identification of this issue in conjunction with several other procedure upgrade project issues is reflective of a significant programmatic deficiency in coordination of maintenance and operations procedures. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function for greater than the Technical Specification allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors determined that this finding was cross-cutting in the Human Performance, Resources area because the licensee did not have complete, accurate and up to date procedures regarding testing of the 12 diesel-driven cooling water pump and realignment of the 121 motor-driven cooling water pump (H.2(c)). (Section 1R19.1)

- Green. A self-revealed finding of very low safety significance and a Non-Cited Violation of Technical Specification 5.4.1 were identified on February 27, 2009, due to operations personnel failing to adequately implement procedures which control safety-related equipment. Specifically operations personnel, unintentionally, rendered the 23 instrument inverter inoperable during the performance of on-the-job training activities. Corrective actions for this issue included returning the 23 instrument inverter to an operable status, providing additional training on the use of human error prevention techniques to the apprentice plant attendant, and providing additional training on the instrument inverters.

  The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function of one train of equipment for greater than the Technical Specification allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because human error prevention techniques were not used to ensure that an on-the-job training activity was performed safely (H.4(a)). (Section 4OA3.2)

- Green. A self-revealed finding of very low safety significance and a Non-Cited Violation of Technical Specification 5.4.1 were identified on April 26, 2009, due to maintenance personnel failing to implement procedures which control safety-related equipment. Specifically maintenance personnel did not comply with work order instructions or procedures, rendering the 22 battery charger inoperable during the performance of maintenance on the 22 instrument inverter. Corrective actions for this issue included issuing a stop work order and remediating the maintenance workers on human performance tool use.

  The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function of one train of equipment for greater than the Technical Specification allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because maintenance personnel did not follow procedures during this maintenance activity (H.4(b)). (Section 4OA3.3)

- Green. A self-revealed finding of very low safety significance was identified on April 30, 2009, due to operations personnel failing to implement procedures which control plant equipment. Specifically operations personnel operated the incorrect component, rendering the 122 air compressor non-functional during the performance of independent verification activities. Corrective actions for this issue included restoring the 122 air compressor to a functional status and briefing operations personnel on the details/lessons learned from this event.

The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function for one or more non-Technical Specification trains of equipment for greater than 24 hours, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Decision Making area because the operator failed to use conservative assumptions when making the decision regarding the need to operate breaker 121E-6, 1A2-B4 (H.1(b)). No violation of NRC requirements was identified because the air compressor was non-safety related. (Section 4OA3.4)

Cornerstone: Barrier Integrity

- Green. A self-revealed finding of very low safety significance and an Non-Cited Violation of Technical Specification 5.4.1 were identified on March 25, 2009, due to the failure of licensed operators to maintain control of the Unit 1 containment personnel airlock outer door. This resulted in the Unit 1 containment personnel airlock being unknowingly inoperable for approximately 45 minutes. Corrective actions for the issue included returning the Unit 1 containment airlock outer door to an operable status, developing a case study for inclusion during licensed operator training, and developing a procedure on operating the containment airlock doors.

  This finding was determined to be more than minor because if left uncorrected the failure to fully understand and control the configuration of plant equipment could become a more significant safety concern. The inspectors determined that this finding was of very low safety significance because it did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, or spent fuel pool; the finding did not represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere; the finding did not represent an actual open pathway in the physical integrity of reactor containment due to the inner airlock door being fully closed; and the finding did not involve an actual reduction in function of the hydrogen igniters in the reactor containment. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel failed to follow procedures regarding the requirement to maintain an awareness of the configuration of plant equipment at all times (H.4(b)). (Section 1R15.1b(2))

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken 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

Summary of Plant Status

Unit 1 began the inspection period at full power. On May 16, 2009, operations personnel lowered reactor power to 40 percent to conduct turbine valve testing and condenser waterbox cleaning. Unit 1 returned to full power on May 17, 2009. At 1:05 p.m. the following day, Unit 1 automatically shut down after experiencing a high differential pressure condition on the main condenser. The high differential pressure condition was caused by an unexpected loss of the 12 circulating water pump. The licensee determined that the 12 circulating water pump was lost due to a ground fault on a power cable. Operations personnel returned Unit 1 to service on May 22, 2009. For the next 3.5 days, operations personnel operated Unit 1 at approximately 50 percent power while repairs were made to the 12 circulating water pump. Unit 1 returned to full power on May 26, 2009, following replacement of the 12 circulating water pump's power cables. Unit 1 operated at full power for the remainder of the inspection period.

Unit 2 operated at full power until May 9, 2009, when reactor power was lowered to 40 percent to conduct condenser waterbox cleaning and turbine valve testing. Unit 2 was restored to full power on May 10, 2009, and operated at that level for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Onsite Alternating Current Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of the offsite and onsite alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the TSO and the licensee during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to the licensee when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- The compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- A re-assessment of plant risk based on maintenance activities which could affect grid reliability or the ability of the transmission system to provide offsite power; and
- The communications between the licensee and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness of offsite and onsite AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Safety Analysis Report (USAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Documents reviewed during this inspection are listed in the Attachment. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station procedures. The inspectors' review focused on the following:

- The impact of an identified tornado missile issue on the Unit 1 component cooling water system and spent fuel pool cooling system and
- The screenhouse ventilation system.

This inspection constituted one seasonal adverse weather sample as defined in IP 71111.01-05.

b. Findings

No findings of significance were identified. Further analysis of the tornado missile issue is documented in NRC Inspection Report (IR) 05000282/2009010; 05000306/2009010.

.3 External Flooding

a. Inspection Scope

On March 27, 2009, operations personnel entered Abnormal Operating Procedure AB-4, “Flood,” due to the 3 day forecasted river level being greater than 678 feet. The inspectors reviewed the abnormal operating procedure and the compensatory measures needed to mitigate the predicted flooding conditions to ensure they could be implemented as written. The inspectors evaluated the design and material condition of equipment used to mitigate flooding conditions and toured low lying areas to identify potential in-leakage. The inspectors also performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during the predicted flood conditions or allow water ingress past a barrier. Operations personnel exited AB-4 on April 3, 2009. No significant flooding was experienced at the station.

This inspection constituted one external flooding adverse weather sample as defined in IP 71111.01-05

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- Fuel Pool Cooling System;
- 22 Diesel-Driven Cooling Water Pump and Piping; and
- Emergency Diesel Generator D2 while D1 was out of service for a cylinder liner replacement.

The inspectors selected these systems 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, USAR, Technical Specifications (TS) requirements, outstanding work orders (WOs), CAPs, 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 CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted three partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

.2 Semi-Annual System Walkdown Via Operating Experience Smart Sample (OpESS) 2009-02: Negative Trend and Recurring Events Involving Feedwater Systems

a. Inspection Scope

Between May 29 and June 30, 2009, the inspectors performed a system alignment inspection of the feedwater system to verify its functional capability. This system was selected because equipment misalignment or operational issues could cause a plant transient or trip. The inspectors reviewed OpESS FY 2009-02, "Negative Trend and Recurring Events Involving Feedwater Systems," in preparation for this inspection. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications; 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 are listed in the Attachment.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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:

- Auxiliary Building 695-foot Elevation (Fire Area 58, Zones 8 and 108);
- D5 4 Kilovolt (kV) Bus 25 Room (Fire Area 117, Zone 97-7);
- D6 4 kV Bus 26 Room (Fire Area 118, Zone 97-8);
- Control Room (Fire Area 13, Zone 57);
- Relay and Cable Spreading Room (Zone 12, Area 18); and
- Auxiliary Building 695-foot Elevation (Fire Area 73, Zone 40).

The inspectors reviewed 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 licensee'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 licensee'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. Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the USAR, engineering evaluations, and abnormal operating procedures as part of this inspection. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding. The inspectors also reviewed the licensee's CAP with respect to past flood-related items to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas:

- Unit 1 Turbine Building;
- Unit 2 Turbine Building.

This inspection constituted two internal flooding samples as defined in IP 71111.06-05.

b. Potential Flooding Impact on Safety-Related Equipment

Introduction: One unresolved item was identified due to the potential that internal flooding following a random pipe break or high energy line break (HELB) event in the turbine building could result in the loss of safety-related mitigating systems equipment.

Description: As part of the ongoing review of the potential interaction between high energy lines and the component cooling water system (discussed in NRC IR 05000282/2008005; 05000306/2008005 and 05000282/2009010; 05000306/2009010), a potential internal flooding issue was identified. Specifically, the licensee postulated that a turbine building HELB could result in the subsequent failure of cooling water piping and actuation of the fire protection sprinklers such that an unlimited supply of water could be introduced into the turbine building. This unlimited supply of water could potentially result in an internal flooding event that impacted the availability of redundant safety-related equipment that was required to respond to an event.

The inspectors discussed the internal flooding licensing basis with regulatory assurance and engineering personnel. The licensing basis stated that a rupture of a high energy pipe cannot directly or indirectly result in a loss of redundant safety equipment required to mitigate the event. The licensing basis also stated that the potential for flooding safety-related equipment due to a HELB event must be evaluated. Lastly, NRC design requirements state that failures of non-safety related systems must not result in the complete failure of safety-related equipment.

The licensee conducted a review and determined that flooding effects due to a HELB or random pipe break had not been analyzed. As a result, it was not clear whether a postulated HELB or random pipe break event could result in internal flooding of the turbine building that would impact the availability of safety-related/mitigating systems equipment. The licensee was conducting several evaluations at the conclusion of the inspection period. As discussed in Section 1R15 of this inspection report, the licensee performed an operability evaluation of this potential flooding concern and determined that compensatory measures were needed to ensure that the water resulting from the potential internal flooding event would not accumulate in the turbine building and result in the unavailability of mitigating systems equipment. However, the potential for safety-related equipment to be impacted by internal flooding following a HELB or a random pipe break was considered unresolved pending a review of the licensee's analyses (URI 05000282/2009003-01; 05000306/2009003-01).

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On June 2, 2009, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew’s performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Reactor Protection System, and
- Service Air System.

The inspectors reviewed events such as where ineffective equipment maintenance had 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;
- 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; and
- verifying appropriate performance criteria for structures, systems, and components/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 to this report.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

No findings of significance were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Orange risk condition due to inoperability of two cooling water pumps for planned maintenance;
- Planned maintenance on the Blue Lake 345 kV power line and the 121 motor-driven cooling water pump (MDCLP);
- Planned maintenance on the D1 emergency diesel generator (EDG);
- Planned maintenance on the 122 auxiliary building special ventilation system and the D2 EDG with emergent work on the 122 safeguards chilled water system;
- Emergent work on a 345 kV Bus 1 lightening arrestor;
- Planned Maintenance on the 22 component cooling water heat exchanger with emergent work on the D6 EDG and potential severe weather; and
- Emergent work on the 121 safeguards traveling screen.

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 maintenance risk assessment and emergent work control activities constituted seven samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- CAP 1174897 – Unplanned Entry into TS 3.6.2 Due to Unsecured Unit 1 Containment Personnel Airlock;
- Operability Recommendation 1178236 – Potential Turbine Building Flooding Issues Following a HELB;
- Operability Recommendation 1144451, Revision 1 – Emergency Intake Line 100 Percent Blocked Following Design Basis Earthquake;
- CAP 1166911 – Tube Leak on D1 EDG Lube Oil Heat Exchanger (this sample was inspected for a potential common mode failure of the D2 EDG heat exchangers and past operability of the D1 EDG);
- Operability Recommendation 1128843 – Unit 2 Pressurizer Surge Line Restraint Gaps;
- CAP 1176859 – Broken EDG Bearing Oil Sight Glass; and
- CAPs 1174714 and 1174780 – Past D1 EDG Operability Due to Coolant and Oil Leakage.

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 USAR 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. Documents reviewed are listed in the Attachment to this report.

This operability inspection constituted seven samples as defined in IP 71111.15-05

b. Findings

(1) Failure to Adequately Control Compensatory Measures

Introduction: The inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, on April 28, 2009, for failure to have adequate procedures to control compensatory actions for degraded/non-conforming conditions. Specifically the failure to implement positive controls for the Unit 2 roll-up door as a compensatory measure for an operability determination invalidated the determination.

Description: On April 15, 2009, the licensee identified that a turbine building HELB could potentially result in internal flooding that impacted the operability of mitigating systems equipment. Although engineering personnel believed that sufficient time was available for the operators to perform mitigating actions, operations personnel requested that an operability determination be completed. As the licensee continued to review this issue, they became concerned regarding their continued ability to complete the mitigating actions within the required time. On April 24, the licensee initiated and implemented compensatory measures to ensure that mitigating systems equipment was not impacted following the postulated HELB/pipe break and internal flooding event. The compensatory measures consisted of opening the turbine building roll-up doors 18 inches or more. Operations personnel verified the adequacy of the compensatory measures approximately every 6 hours.

On April 28, 2009, operations personnel initiated CAP 1179979 when they found that the Unit 2 roll-up door was only 14 inches open. At the time of discovery, there were tags hanging on the control push buttons for the roll-up doors instructing that the doors needed to remain greater than or equal to 18 inches open. However, there were no positive controls put in place to ensure that the doors always remained in this position. In addition, there were no markings placed on the doors to indicate the 18 inch criteria. The inspectors reviewed Procedure FP-OP-OL-01-PI, "Operability/Functionality Determination," and concluded that this issue occurred due to procedural inadequacies. Specifically, the procedure did not include guidance on the need to positively control the configuration of compensatory measures to ensure the measures were not invalidated.

Analysis: The inspectors determined that the failure to have adequate procedures to implement positive controls to ensure that operability determination compensatory measures were not invalidated was a performance deficiency that impacted the Mitigating Systems cornerstone and required evaluation using the SDP. The inspectors determined that the finding was more than minor because if left uncorrected the failure to properly control compensatory measures could result in rendering equipment inoperable (a more significant safety concern). The inspectors determined that this finding was of very low safety significance because it was not a design or qualification deficiency, did not result in a loss of system safety function or the loss of a single train for greater than the TS allowed outage time, and it did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event since the roll-up door was 14 inches open and would have provided some mitigation following an internal flood. The inspectors determined that this issue was cross-cutting in the Human Performance, Resources area because the licensee failed to ensure that the operability determination procedure was adequate in regards to the control of compensatory measures (H.2(c)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by procedures appropriate to the circumstances. The completion of operability determinations was an activity affecting quality prescribed by Procedure FP-OP-OL-01-PI. Contrary to the above, on April 28, 2009, Procedure FP-OP-OL-01-PI was demonstrated to be inappropriate to the circumstances. Specifically, a compensatory measure put in place as part of an operability determination was invalidated due to the procedure failing to require the implementation of positive configuration control over all compensatory measures. Because this finding was of very low safety significance, and because it was entered into the CAP as CAP 1179979, this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000282/2009003-02; 05000306/2009003-02). Corrective actions for this issue included opening the roll-up door to greater than 18 inches open, implementing positive configuration controls for the compensatory measures, and revising the operability determination procedure to require the implementation of positive controls.

(2) Unit 1 Containment Personnel Airlock Door

Introduction: A self-revealed Green finding and an NCV of TS 5.4.1 were identified on March 25, 2009, due to the failure of licensed operators maintain control of the Unit 1 containment personnel airlock outer door. This resulted in entering an unplanned TS limiting condition for operation due to the inoperable door.

Description: On March 25, 2009, licensee personnel entered the Unit 1 containment to sample the Unit 1 accumulators. At 10:17 a.m., a radiation protection (RP) technician notified the Unit 1 reactor operator (RO) that personnel were exiting the Unit 1 containment. The RP technician informed the Unit 1 RO that he would contact the control room after the Unit 1 containment personnel air lock outer door was closed and locked. At the time of the phone call, the Unit 1 Lead RO was outside of the control room. The RO informed the Lead RO of the RP technician's phone call when the Lead RO returned to the control room.

Thirteen minutes later, the Unit 1 Lead RO received a call from the RP technician stating that the Unit 1 containment personnel airlock outer door was closed and locked. Sometime between 10:30 a.m. and 11:18 a.m., the Lead RO directed the auxiliary building operator to perform Surveillance Procedure (SP) 1132, "Unit 1 Maintenance and Personnel Airlock Door Seal Test." At 11:00 a.m. the Lead RO performed a required walkdown of the control room panels and failed to identify that two lit indications existed showing the airlock door was not closed. At 11:18 a.m. the auxiliary building operator reported that the Unit 1 personnel airlock outer door leakage failed to meet the acceptance criteria specified in the SP. In addition, the auxiliary building operator stated that there was an audible air leak coming from the door seals. Following this conversation, the Unit 1 Lead RO checked his control room indications and discovered that a containment isolation light and a control room annunciator for the Unit 1 personnel airlock were lit due to the personnel airlock outer door not being fully closed. Operations personnel immediately entered TS 3.6.2 due to the unplanned inoperability of the personnel airlock outer door. Operations personnel closed and locked the outer door and reperformed SP 1132 satisfactorily.

The inspectors reviewed the licensee's apparent cause evaluation report associated with this event. As part of the apparent cause investigation, the licensee determined that control room personnel had three opportunities to identify that the Unit 1 containment personnel airlock outer door had been left open prior to performing SP 1132. First, the control room operators failed to verify that the containment isolation light and the annunciator were not lit after receiving information from the RP technician that the airlock door had been closed and locked. Second, the control room operators failed to question the status of the light and the annunciator during their hourly control panel walkdowns. Third, the control room supervisors failed to question the status of the light and annunciator as part of their control room oversight activities. The licensee believed that the control room staff failed to identify the issue with the containment airlock door because they were distracted by other activities including a control room computer system being out of service, multiple turbine control valve position limit alarms, component cooling water flow limitations, and an emergent tagging issue on the D1 EDG.

<u>Analysis</u>: The inspectors determined that the failure of licensed operators to be cognizant and control the Unit 1 containment personnel airlock outer door's status was a performance deficiency that impacted the Barrier Integrity cornerstone and required evaluation using the SDP. This finding was determined to be more than minor because if left uncorrected the failure to fully understand the status of plant equipment could become a more significant safety concern. The inspectors determined that this finding was of very low safety significance because it did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, or spent fuel pool; the finding did not represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere; the finding did not represent an actual open pathway in the physical integrity of reactor containment due to the inner airlock door being fully closed; and the finding did not involve an actual reduction in function of the hydrogen igniters in the reactor containment. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel failed to follow procedures regarding the need to maintain awareness of the configuration of plant equipment at all times (H.4(b)).

<u>Enforcement</u>: Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Section 1.b of Regulatory Guide 1.33 requires procedures governing the authorities and responsibilities for safe operation and shutdown, and Section 1.c required procedures regarding equipment control. The licensee used procedure FP-OP-COO-01, "Conduct of Operations," to satisfy those sections of Regulatory Guide 1.33. Section 3.5 of FP-OP-COO-01, Attachment 7, "Equipment Manipulation and Status Control," required that equipment configuration shall be controlled such that the status of plant equipment is known at all times.

Contrary to the above, on March 25, 2009, licensed operators failed to control the configuration of the Unit 1 containment personnel airlock outer door such that the status of the door was known at all times. Specifically, the operators failed to use control room indications to identify that the Unit 1 containment personnel airlock outer door had not been fully closed after receiving communications from an RP technician and during hourly control board walkdowns. Because this violation was of very low safety significance and was entered into the CAP as CAP 1174897, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000282/20090003-03). Corrective actions for the issue included returning the Unit 1 containment airlock outer door to an operable status, developing a case study for inclusion during licensed operator training, and developing a procedure on operating the containment airlock doors.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- SP 1106C – 121 Cooling Water Pump Quarterly Test following the replacement of the 121 MDCLP;
- SP 1295 – D1 EDG Fast Start Test following engine cylinder liner replacements;
- WO Task 354829-06-16 – Post Maintenance Testing of D5 EDG following 2-year mechanical inspection;
- Return to service testing on the 12 circulating water pump;
- Testing following a D1 EDG failed surveillance and exhaust fire;
- WO 370918 – Testing of the 11 heater drain tank pump following maintenance;
- Testing following a D6 EDG boroscopic inspection;
- Testing following a Bus 16 power supply replacement; and
- Testing following maintenance on the 12 diesel-driven cooling water pump.

These activities were selected based upon the structures, systems, and components' 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 USAR, 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 CAP documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them into the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted nine post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

Unplanned Start of 121 Motor-Driven Cooling Water Pump

Introduction: A self-revealed Green finding and an NCV of 10 CFR Part 50, Appendix B, Criterion V were identified on March 19, 2009, due to the failure to have adequate procedures to adequately control maintenance activities to ensure that plant equipment was not unnecessarily challenged. Specifically, the failure to adequately control maintenance on the 12 Diesel Driven Cooling Water Pump (DDCLP) resulted in the automatic start of the 121 Motor-Driven Cooling Water Pump (MDCLP) during post-maintenance testing activities.

Description: During the week of March 16, the licensee performed scheduled maintenance on the 12 DDCLP. As part of this maintenance, operations personnel were initially required to align the 121 MDCLP as a safety-related pump. The 121 MDCLP needed to be realigned as a non-safety related pump prior to testing the 12 DDCLP.

On March 18, 2009, the shift technical advisor (STA) reviewed the procedures associated with testing the 12 DDCLP and identified that the need to realign the 121 MDCLP to a non-safety related configuration was discussed in Procedure 1M-CL-3002-2-12, "Isolation and Restoration of 12 Diesel-Driven Cooling Water Pump for Preventive Maintenance Procedure PM 3002-2-12." However, these actions were not discussed in Procedure PM 3002-2-12, "12 Diesel-Driven Cooling Water Pump Diesel Minor Maintenance." Procedure PM 3002-2-12 also did not refer to Procedure 1M-CL-3002-2-12 to ensure that the 121 MDCLP was realigned prior to testing the 12 DDCLP. The need to realign the 121 MDCLP prior to testing the 12 DDCLP was also not listed on the daily work control schedule. No actions were taken to correct these deficiencies even though the licensee's processes required that direct references to procedures be made when multiple procedures are used to complete work activities.

The licensee initially planned to perform post-maintenance testing on the 12 DDCLP on March 18. Work delays resulted in rescheduling the test for March 19. Prior to performing the test, operations personnel performed a pre-job briefing of the activity. Although the STA was involved in this briefing, the information regarding the procedures (discussed above) was not discussed. Following the pre-job brief, the STA approved the start of the test. The 12 DDCLP was locally started and trip tested in accordance with PM 3002-2-12. Immediately following the trip test, the cooling water system experienced a pressure transient that resulted in automatically starting the 121 MDCLP. The automatic start would not have happened if the 121 MDCLP had been properly aligned prior to the post-maintenance test.

The licensee determined that actions taken as part of the procedure upgrade project may have contributed to this event. Specifically, previous versions of the licensee's maintenance procedures used to be all-inclusive (that is, they included the instructions for the entire maintenance activity including removal of the equipment from service and post-maintenance testing instructions). However, the licensee completed a procedure upgrade project that resulted in the generation of several procedures for performing maintenance rather than one all-inclusive procedure. The procedure upgrade project was completed so that Prairie Island aligned with industry standards regarding maintenance procedures and the overall work control process. The inspectors determined that operations personnel responded appropriately to the automatic pump start. The cooling water system was returned to an operable status later the same day.

Analysis: The inspectors determined that the failure to have adequate procedures to adequately control maintenance activities to ensure that plant equipment was not unnecessarily challenged was a performance deficiency that impacted the Mitigating Systems cornerstone and required evaluation using the SDP. The inspectors determined that this finding was more than minor because, if left uncorrected, the failure to properly control maintenance activities could become a more significant safety concern. In addition, the inspectors determined that the identification of this issue in conjunction with several other procedure upgrade project issues is reflective of a significant programmatic deficiency in coordination of maintenance and operations procedures. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function for greater than the TS allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors determined that this finding was cross-cutting in the Human Performance, Resources area because the licensee did not have complete, accurate and up to date procedures regarding testing of the 12 DDCLP and realignment of the 121 MDCLP (H.2(c)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality be performed in accordance with instructions, procedures, and drawings appropriate to the circumstance. Contrary to the above, on March 19, 2009, Procedure PM 3002-2-12 was not appropriate to the circumstance. Specifically, the procedure failed to include procedure steps or provide a reference to another procedure to ensure that the 121 MDCLP was realigned to a non-safety related configuration prior to testing the 12 DDCLP. Because this violation was of very low safety significance and it was entered into the CAP as CAP 1173880, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000282/20090003-04; 05000306/20090003-04). Corrective actions for this issue included adding instructions to the maintenance procedure to ensure that it properly referenced the procedure used to realign the 121 MDCLP. The licensee planned to complete a review of safety-related preventive maintenance procedures to ensure that proper procedure referencing and branching was utilized. Lastly, the licensee will add additional staff to assist with the procedure upgrade program and to coordinate preventive maintenance activities.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for a forced outage that began on May 18, 2009, following an automatic Unit 1 reactor shut down. The forced outage continued through May 22, 2008. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the forced outage schedule.

The reactor shut down was reviewed as part of an Event Followup inspection documented in Section 4OA3 of this report. The inspectors observed or reviewed the following areas during the forced outage:

- equipment configuration;
- risk management;
- electrical lineups;
- control and monitoring of decay heat removal; and
- startup and heatup activities.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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:

- SP 1091 - Monthly Containment Fan Coil Units Surveillance Test (Unit 1);
- SP 2091 - Monthly Containment Fan Coil Units Surveillance Test (Unit 2);
- SP 2035 - D6 EDG Monthly Slow Start Test;
- 121 MDCLP in-service testing following a pump replacement;
- SP 2132 - Unit 2 Personnel and Maintenance Airlock Door Seal Test;
- SP 1130A - Train A Containment Vacuum Breakers Quarterly Test;
- SP 1094 - Bus 15 Load Sequencer Test.

The inspectors observed in plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, 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;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples, one inservice testing sample, and two containment isolation valve samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine emergency drill on April 14, 2009, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator, the technical support center, and the emergency operations facility to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee's critique to compare any inspector-observed weakness with those identified by the licensee. Following the critique, the inspectors reviewed the licensee's CAP to ensure that all identified weaknesses were entered into the system and appropriately evaluated. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's Occupational Exposure Control cornerstone performance indicator (PI) to determine whether the conditions resulting in any PI occurrences had been evaluated and whether identified problems had been entered into the licensee's CAP for resolution.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Preparation and Loading of Spent Fuel Cask No. 25.

This inspection constituted a partial sample as defined in IP 71121.01-5.

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these areas and other high radiation work areas. The inspectors assessed the work control instructions and control barriers specified by the licensee. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors interviewed workers to verify that they were aware of the actions required if their electronic dosimeters noticeably malfunctioned or alarmed.

This inspection constituted a partial sample as defined in IP 71121.01-5.

The inspectors walked down and surveyed (using an NRC survey meter) these areas to verify that the prescribed RWP, procedure, and engineering controls were in place; that licensee surveys and postings were complete and accurate; and that air samplers were properly located.

This inspection constituted a partial sample as defined in IP 71121.01-5.

The inspectors assessed the adequacy of the licensee's internal dose assessment process for internal exposures in excess of 50 millirem committed effective dose equivalent. There were no internal exposures greater than 50 millirem committed effective dose equivalent.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool or other storage pools.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a sample of the licensee's self-assessments, audits, Licensee Event Reports (LERs), and Special Reports related to the access control program to verify that identified problems were entered into the CAP for resolution.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors reviewed CAPs related to access controls and any high radiation area radiological incidents (issues that did not count as PI occurrences identified by the licensee in high radiation areas less than 1R/hr). Staff members were interviewed and CAPs were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors evaluated the licensee's process for problem identification, characterization, and prioritization and verified that problems were entered into the CAP and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors reviewed licensee documentation packages for all PI events occurring since the last inspection to determine if any of these PI events involved dose rates in excess of 25 R/hr at 30 centimeters or in excess of 500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. Unintended exposures exceeding 100 millirem total effective dose equivalent (or 5 rem shallow dose equivalent or 1.5 rem lens dose equivalent) were evaluated to determine if there were any regulatory overexposures or if there was a substantial potential for an overexposure.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Preparation and Loading of Spent Fuel Cask No. 25.

The inspectors reviewed radiological job requirements for these activities, including RWP requirements and work procedure requirements, and attended As-Low-As-Reasonably-Achievable (ALARA) job briefings.

This inspection constituted a partial sample as defined in IP 71121.01-5.

Job performance was observed with respect to the radiological control requirements to assess whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors evaluated the adequacy of radiological controls, including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage, including any applicable audio and visual surveillance for remote job coverage; and contamination controls.

This inspection constituted a partial sample as defined in Inspection Procedure 71121.01-5.

The inspectors reviewed radiological work in high radiation work areas having significant dose rate gradients to evaluate whether the licensee adequately monitored exposure to personnel and to assess the adequacy of licensee controls. These work areas involved areas where the dose rate gradients were severe; thereby increasing the necessity of providing multiple dosimeters or enhanced job controls.

This inspection constituted a partial sample as defined in Inspection Procedure 71121.01-5.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate, High Radiation Area and Very High Radiation Area Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager concerning high dose rate, high radiation area and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to assess whether any procedure modifications substantially reduced the effectiveness and level of worker protection.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors discussed with radiation protection supervisors the controls that were in place for special areas of the plant that had the potential to become very high radiation areas during certain plant operations. The inspectors assessed if plant operations required communication beforehand with the radiation protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

This inspection constituted one sample as defined in IP 71121.01-5.

The inspectors conducted plant walkdowns to assess the posting and locking of entrances to high dose rate high radiation areas and very high radiation areas.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation safety work requirements. The inspectors evaluated whether workers were aware of any significant radiological conditions in their workplace, of the RWP controls and limits in place, and of the level of radiological hazards present. The inspectors also observed worker performance to determine if workers accounted for these radiological hazards.

This inspection constituted a partial sample as defined in IP 71121.01-5.

The inspectors reviewed radiological problem reports for which the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. Problems or issues with planned or completed corrective actions were discussed with the Radiation Protection Manager.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation safety work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

This inspection constituted a partial sample as defined in Inspection Procedure 71121.01-5.

The inspectors reviewed radiological problem reports for which the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

This inspection constituted one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Reasonably-Achievable Planning And Controls (71121.02)

.1 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee’s list of work activities ranked by estimated exposure that were in progress and reviewed the following three work activities of highest exposure significance:

- Unit 2 Pressurizer Weld Overlay (2R25);
- Reactor Head Set (2R25); and
- Preparation and Loading of Spent Fuel Cask No. 25.

This inspection constituted one required sample as defined in IP 71121.02-5.

For these three activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. The inspectors also determined if the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

This inspection constituted one required sample as defined in IP 71121.02-5.

The inspectors compared the results achieved (including dose rate reductions and person-rem used) with the intended dose established in the licensee's ALARA planning for these three work activities. Reasons for inconsistencies between intended and actual work activity doses were reviewed.

This inspection constituted one required sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

.2 Declared Pregnant Workers.

a. Inspection Scope

The inspectors reviewed dose records of declared pregnant workers for the current assessment period to verify that the exposure results and monitoring controls employed by the licensee complied with the requirements of 10 CFR Part 20.

This inspection constituted one required sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for Units 1 and 2 for the period from the second quarter of 2008 through the first quarter of 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance were used. The inspectors reviewed the operator logs, operability assessments, maintenance rule records, WOs, CAPs, event reports and NRC Integrated Inspection Reports for the period of April 2008 through March 2009 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two safety system functional failures samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the Reactor Coolant System (RCS) Leakage PI for Units 1 and 2 for the period from the second quarter of 2008 through the first quarter of 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, CAPs, event reports and NRC Integrated Inspection Reports for the period of the second quarter 2008 through the first quarter 2009 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two RCS leakage samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.3 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Specific Activity PI for Units 1 and 2 for the period from the second quarter 2008 through the first quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, was used. The inspectors reviewed the licensee's RCS chemistry samples, TS requirements, CAPs, event reports, and NRC Integrated Inspection Reports for the period of second quarter 2008 through the first quarter 2009, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. In addition to record reviews, the inspectors observed a chemistry technician obtain and analyze an RCS sample. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two reactor coolant system specific activity samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.4 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences PI for the period from the third quarter 2008 through the first quarter 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review, and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational radiological occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered Into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in other sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program 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 CAP reports.

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.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above. The inspectors' review nominally considered the 6 month period of January through June 2009, although some examples expanded beyond those dates where the scope of the trend warranted. The review also included issues documented outside the normal CAP in major equipment problem lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending information.

This review constituted a single semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

(1) Previously Identified Trend - Ability to Identify and Thoroughly Evaluate Problems

In June 2008, the inspectors identified an adverse trend in the licensee's ability to promptly identify and/or thoroughly evaluate problems. Six months later, the inspectors found that this adverse trend had continued. In addition, the trend appeared to be caused by weaknesses in procedure use and adherence. The inspectors performed multiple inspections and reviewed daily CAP reports during the last 6 months. Based upon this review, the inspectors concluded that this adverse trend had continued. The specific examples are as follows:

- On November 6, 2008, operations personnel failed to implement abnormal operating procedures following an unexpected control rod insertion on Unit 2. The failure to implement the abnormal operating procedures was due to receiving training that directly conflicted with the licensee's procedure use and adherence requirements. This issue was documented as a Green finding and an NCV by the NRC. See NRC IR 05000282/2008005; 05000306/2008005 and IR 05000282/2009002; 05000306/2009002 for additional details.

- In December 2008, the inspectors identified that the licensee had failed to fully implement the operability evaluation procedure. As a result, the licensee failed to identify that information regarding the continued ability of the 122 control room chiller to operate for its required mission time had not been included in the determination. This issue was entered into the CAP as CAP 1162312. This issue was also documented as a Green finding and an NCV in Section 1R15.1 of NRC IR 05000282/2009002; 05000306/2009002.

- During a training activity on a safety-related inverter, a trainee intended to point to a label for a light that indicated whether the alternate power source was supplying the static switch. However, the trainee inadvertently depressed a pushbutton that rendered the inverter inoperable. The failure of the trainee to self-check himself/herself prior to performing the action was contrary to licensee procedures. This issue was entered into the CAP as CAP 1171241. This issue was determined to be a self-revealed Green NCV of TS 5.4.1 that was documented in Section 4OA3.2 of this inspection report.

- During work activities on a safety-related inverter, maintenance personnel identified the need to implement additional industrial safety measures due to working near energized equipment. The workers failed to fully evaluate the situation presented to them and took actions to implement the additional industrial safety measures rather than stopping, returning the work package to maintenance planning, and seeking further guidance. This action was contrary to the WO instructions which stated that the work package was required to be returned to maintenance planning if additional industrial safety guidance was needed. In addition, the workers actions resulted in rendering the 22 battery charger inoperable. This issue was documented as CAP 1179638. This issue was also documented as a self-revealed Green finding and an NCV of TS 5.4.1 in Section 4OA3.3 of this inspection report.

- On April 30, 2009, an operator was assigned to independently verify that the breaker for the 121 air compressor had been left in the off position as part of a clearance order final clear checklist. Prior to performing the independent verification activity, the operator was provided a detailed pre-job brief. After the operator entered the air compressor room, he proceeded to a motor control center and located the breaker that he believed required the independent verification. The operator immediately recognized that the breaker he had located was in the on position rather than the off position. Although all plant personnel were trained to stop when unexpected plant conditions were encountered, the operator assumed that the clearance order tag remover had not correctly positioned the breaker. In addition, the operator failed to compare the breaker number of the breaker he had located against the breaker number listed on the final clear checklist. These errors resulted in the operator opening the breaker for the running 122 air compressor instead of checking the breaker for the 121 air compressor off. This issue was documented in CAP 1180343. This issue was also documented as a self-revealed Green finding in Section 4OA3.4 of this inspection report.

- During Unit 2 turbine valve testing on May 9, 2009, operations personnel identified conflicting information regarding setting of the turbine valve position limiter. Although the operators stopped when they encountered this conflicting information, they failed to request assistance from other knowledgeable individuals regarding the operation and setting of the valve position limiter. In addition, the operations crew failed to ensure that procedures used to complete the turbine valve test were adequate prior to beginning the testing activities. This directly conflicted with the licensee's procedure regarding procedure use and adherence. This issue was documented as a self-revealed Green finding in Section 4OA3.5 of this inspection report.

- On May 15, 2009, a worker was cleaning up his work area after completing an inspection of the 122 battery room refrigeration unit. During this cleaning activity, the worker noticed several pipe caps lying on the floor. In an effort to keep the pipe caps from being lost, the worker reinstalled the pipe caps. However, the worker did not know that the pipe caps were required to be left off per the directions in the clearance order checklist associated with the battery room refrigeration unit work. This issue was documented in CAP 1182301. While these actions violated the procedural requirements associated with clearance and tagging activities, this violation was determined to be minor since the 122 battery room refrigeration unit was out of service when the pipe caps were installed.

- On May 20, 2009, a contract supervisor and three workers passed through a radiation area boundary without being signed on to an RWP and without the required dosimetry. This violated the RWP and dosimetry requirements posted on the swing gate at the entrance to the radiation area. This issue was documented in CAP 1182603. This issue remained under review by a Region III radiation protection specialist.

On June 24, 2009, the licensee approved a procedure use and adherence improvement plan. The licensee has also implemented an additional plan to address the timely identification and thorough evaluation of issues. The inspectors were unable to assess the effectiveness of these plans due to their recent implementation. The inspectors planned to review the implementation of these plans as part of the next semi-annual adverse trend review.

<u>New Trend – Untimely Implementation of Actions Following Operating Experience Reviews</u>

In late 2008 the inspectors began reviewing a potential HELB issue within the turbine building in detail (see NRC IR 05000282/2008005; 05000306/2008005). During this review, the inspectors identified that the licensee had operating experience information and HELB review results available to them which indicated that the component cooling water system was susceptible to failure due to a HELB in the turbine building. However, the licensee had taken little action to resolve the HELB concern (this issue is documented in NRC IR 05000282/2009010; 05000306/2009010).

During this inspection period, several other examples regarding the untimely implementation of actions to address operating experience reviews were identified. Of the five additional examples identified, two were identified by the inspectors, one was identified by the licensee, and two were identified due to self-revealing equipment failures. The examples are as follows:

- On March 31, 2009, the licensee identified that issues identified as part of their operating experience review of the Davis-Besse reactor head degradation issue had not been appropriately resolved. Specifically, the operating experience review requested the licensees identify and resolve long-standing, abnormal conditions. The licensee identified several conditions as part of this review. Specifically, ongoing refueling cavity leakage on both units was identified as the number one item needing resolution. Although the licensee had taken some actions to address the leakage concern, the item has not been resolved. The licensee initiated CAP 1175917 to address this concern. The NRC is reviewing the refueling cavity leakage issue as part of the Prairie Island license renewal application.

- In mid-April 2009 a potential internal flooding issue within the turbine building was identified. The inspectors were aware that a risk significant internal flooding issue had been previously identified at the Kewaunee Nuclear Power Plant. The inspectors requested a copy of the operating experience review that was performed in response to the Kewaunee issue. The inspectors found that the licensee had completed a thorough review of this event and initiated actions to review internal flooding susceptibilities in multiple plant areas. However, no action had been taken to complete these reviews. The internal flooding issue is currently under licensee and NRC review as a URI (Potential Turbine Building Flooding Issue (Section 1R06)).

- As discussed in Section 4OA2.4 of this inspection report, the inspectors performed a detailed review of the licensee’s system used to chemically treat the cooling water system. Multiple examples of industry operating experience were available that documented pipe leaks or piping replacements due to biological fouling. In addition, NRC Generic Letter (GL) 89-13 required licensees to commit to continuously treating their cooling water systems (through chemical means) to prohibit/reduce the potential for biological fouling/intrusion. Although the licensee was aware of the operating experience and their NRC commitments, they failed to recognize that the continued non-functionality of the chemical treatment system was contrary to their NRC commitments.

- On April 22, 2009, operations personnel identified that the 21 component cooling water (CC) pump was vibrating excessively (see Sections 4OA3.6 and 4OA7 of this inspection report). Additional review by maintenance and engineering personnel identified that the pump bearing plate was loose and that bearing failure was imminent. Operations personnel shut down the 21 CC pump for further troubleshooting. During the troubleshooting, maintenance personnel identified that the 21 CC pump's inboard bearing had been installed with an improper fit. The improper fit was due to the failure to have adequate procedures regarding the proper bearing installation. Further review indicated that the bearing installation procedures were inadequate because the licensee had failed to update the procedure with critical information contained in the vendor manual. The licensee initiated CAP 1179272 in response to this issue.

- On May 18, 2009, Prairie Island Unit 1 automatically shut down following the unexpected loss of a circulating water pump. Although this issue remained under NRC review, the licensee has indications that the circulating water pump failed due to the untimely implementation of operating experience actions. The licensee documented this issue in CAP 1183067.

On May 26, 2009, the licensee initiated CAP 1183142 to document an adverse trend in the resolution of operating experience items. The licensee planned to perform a common cause evaluation of this issue to better understand why operating experience issues were not being appropriately resolved. On June 17, 2009, the licensee initiated CAP 1185859 to document the need to perform a snapshot self assessment on the use of operating experience at Prairie Island. The inspectors planned to review the common cause evaluation and the snapshot self assessment as part of their next adverse trend review.

.4 Selected Issue Follow-Up Inspection: Review of System Used to Chemically Treat the Cooling Water System

a. Scope

From February 6 through June 12, 2009, the inspectors performed a detailed review of the licensee's chemical injection (CH) system. This system was used to treat the cooling water (service water) coming into the plant so that the potential for biological fouling and/or micro-biologically induced corrosion of piping was minimized. In addition, the inspectors reviewed the licensee's response to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," to form conclusions regarding whether the licensee was meeting their NRC commitments. As part of this inspection, the inspectors reviewed CAP reports, procedures, work requests, and WOs. In addition, the inspectors discussed the CH system and GL 89-13 with engineering, operations, and chemistry personnel. The documents reviewed during this inspection are listed in the Attachment.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Observations

On July 18, 1989, the NRC issued GL 89-13 due to a number of issues regarding the adequacy of service water systems throughout the nuclear industry. In order to address these issues, the NRC requested that each power reactor licensee perform multiple actions to ensure that their service water systems continued to meet regulatory requirements. In addition, nuclear plants that used open-cycle service water systems (such as Prairie Island) were informed of the need to implement and maintain an ongoing program to significantly reduce the incidence of flow blockage problems within the service water system.

The licensee responded to NRC GL 89-13 by letter dated January 29, 1990. As part of this letter, the licensee committed to perform the following actions:

- Visually inspect the intake structure for macroscopic biological fouling organisms once per refueling cycle;
- Continuously chlorinate the service water system (or treat with an equally effective biocide); and
- Perform flushing and testing of infrequently used cooling loops and components.

Prairie Island Nuclear Generating Plant relied upon the CH system to provide continuous treatment of the CL system. The CH system operated by injecting biocide into a diffusion nozzle in the suction piping for the continuously-running, non-safety related 11 and 21 CL pumps. Biocide/chemical injection was not provided for the safety-related CL pumps.

The inspectors reviewed CAP documents and other licensee documentation to determine the operating history of the CH system since January 29, 1990. The inspectors found that the licensee had experienced ongoing operational problems with the CH system since 1990. Specifically, in December 1990, the licensee informed the NRC that the chlorination system initially used to comply with GL 89-13 was being replaced with a hypobromous acid feed system. Approximately six months later, the licensee informed the NRC of inadequacies associated with the hypobromous system. According to documentation reviewed during this inspection, the licensee documented the resolution of the inadequacies in a letter to the NRC dated January 28, 1992.

Approximately 10 years later, the licensee began to experience periodic plugging of the CH system. The licensee initially believed that the plugging was caused by impurities in the dilution water.

In 2004, the licensee identified that the CH system capacity was not adequate to treat the entire CL system during the summer months. On October 14, 2004, plant personnel submitted a request to upgrade the CH system to obtain additional pumping capacity to ensure the system was properly treated during the summer. The additional pumping capacity has yet to be implemented.

On June 12, 2006, the licensee initiated CAP 1035213. This CAP stated that a new chemical injection system was needed prior to the plant entering the license renewal operating period (if the license renewal was approved by the NRC). Although a long range business plan form was filled out in November 2006, a new system has not been installed. In August 2006, the CH system improvements were added to the Radiation Protection and Chemistry Equipment Plan. However, it appears that little was done to implement the needed improvements even though the CH system plugged four times in 2006.

On April 11, 2007, the licensee initiated CAP 1087251 to document needed preparations for improvements to the CH system. Specifically, the licensee planned to convert the CH system from using hypobromous to using hypochlorite and a chemical dispersant. Although the CAP was closed on May 2, 2007, the chemical dispersant was not added to the system until mid-2009. In 2007, the Unit 1 CH system was out of service for approximately 100 days.

In April 2008 the licensee placed the CH system on the Top 10 Equipment Issues List. On June 30, 2008, the licensee wrote a report on raw water system issues and improvements. At the time this report was written, the CH system had been out of service for a significant period of time. Two additional CAPs regarding the need to complete improvements to the CH system were written in July and September 2008.

In October 2008, the licensee identified the presence of multiple live zebra muscles and bryozoa during an inspection of the Unit 2 circulating water bay. This resulted in an additional action to submit an engineering change request to consider modifying the CH system to allow chemical treatment of the safety-related CL pump bays. This request was under consideration at the conclusion of the inspection period. The inspectors reviewed the CH system operating history for 2008 and determined that the Unit 1 CH system was out of service for 135 days. The Unit 2 system was non-functional for 71 days.

Plugging issues continued to plague the CH system in 2009. The Unit 1 and Unit 2 CH systems were out of service from January 19 through April 11, 2009. In April 2009, the licensee implemented the actions to allow the use of a chemical dispersant in the CH system. Since that time, the licensee has experienced little to no plugging of the CH system.

As part of this inspection, the inspectors questioned engineering, chemistry, and licensing personnel to determine whether the licensee believed that the commitments they had made to the NRC as part of their GL 89-13 response had been maintained. The licensee initiated CAPs 1168499 and 1171124 to document the inspectors' questions. The licensee reviewed the information discussed above and concluded that the commitments made to the NRC (in regard to chemically treating the CL system) had not been maintained. The licensee was considering the need to document this in a letter to the NRC at the conclusion of the inspection period. Although the inspectors concluded that the failure to maintain the CH system per GL 89-13 was a performance deficiency, this deficiency was determined to be minor because the lack of chemical treatment of the CL system had not resulted in the degradation or subsequent failure of safety-related or risk-significant equipment. No violations of NRC requirements were identified since the CH system was non-safety related.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 Unit 1 Automatic Reactor Trip

a. Inspection Scope

The inspectors reviewed the licensee's response to a Unit 1 automatic reactor trip that occurred on May 18, 2009. The licensee determined that a cable failure resulted in the 12 circulating water pump shutting down unexpectedly. The shut down of the 12 circulating water pump resulted in an abnormal differential pressure condition within the condenser waterboxes and a shut down of the main turbine. The inspectors reviewed the site personnel and plant response to the event to ensure all safety systems and operators responses were as expected. The inspectors also reviewed the immediate reporting requirements to ensure they were in accordance 10CFR 50.72. The licensee had not completed evaluating the cause of the cable failure at the conclusion of the inspection period. The inspectors planned to conduct an additional review of this issue, and determine whether a performance deficiency occurred, once the licensee's evaluation was completed and an LER had been submitted to the NRC. Documents reviewed in this inspection are listed in the Attachment.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

No findings of significance were identified.

.2 23 Inverter Rendered Inoperable During Training Evolution

a. Inspection Scope

The inspectors reviewed licensee procedures, TSs, operations logs, and the human performance investigation report to determine the circumstances that led to rendering the 23 instrument inverter inoperable on February 27, 2009.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

Introduction: A self-revealed Green finding and an NCV of TS 5.4.1 were identified on February 27, 2009, due to operations personnel failing to adequately implement procedures which control safety-related equipment. Specifically operations personnel, unintentionally, rendered the 23 instrument inverter inoperable during the performance of on-the-job training activities.

Description: On February 27, 2009, an Assistant Plant Equipment Operator (APEO) provided on-the-job training on SP 2313, "Unit 2 Inverter Weekly Inspections," to an Apprentice Plant Attendant (APA). During the training activity, the APEO asked the APA a question regarding readings and indications on the 23 inverter. While answering the question, the APA intended to point to a label for a light that indicated whether the alternate power source was supplying the static switch. However, the APA inadvertently depressed a pushbutton that caused the 23 inverter to transfer to its alternate power source. Immediately following this action the APEO contacted the control room to inform the licensed operators what had happened. The control room operators also received an alarm indicating that the 23 inverter had transferred to its alternate power source.

The control room operators entered 2C20.8 AOP 1, “Abnormal Operation – Instrument Alternating Current Inverters.” Operations also entered TS 3.8.7.a since the transfer of the 23 inverter to its alternate power source rendered the inverter inoperable. The 23 inverter was transferred back to its normal power supply and returned to an operable status approximately 8 minutes later.

Analysis: The inspectors determined that failing to implement procedures, rendering the 23 inverter inoperable during the performance of training activities, was a performance deficiency that impacted the Mitigating Systems cornerstone and required evaluation using the SDP. The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function of one train of equipment for greater than the TS allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because human error prevention techniques were not used to ensure that an on-the-job training activity was performed safely (H.4(a)).

Enforcement: Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 1.b, requires procedures governing the authorities and responsibilities for safe operation and shutdown. In addition, Section 1.c required procedures regarding equipment control.

The licensee used procedure FP-OP-COO-01, “Conduct of Operations,” to satisfy Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Sections 1.b and 1.c.

Section 2.0 of FP-OP-COO-01, Attachment 7, “Equipment Manipulation and Status Control,” required that all equipment manipulations be performed by qualified personnel in accordance with procedures and/or approved by supervision. Contrary to the above, on February 27, 2009, the 22 inverter was manipulated by an individual that was not qualified to do so, without the use of a procedure, and prior to the manipulation being approved by supervision. This manipulation resulted in rendering the 23 instrument inverter inoperable. Because this finding was of very low safety significance, and because it was entered the CAP as CAP 1171241, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy (NCV 05000306/2009003-05). Corrective actions for this issue included returning the 23 instrument inverter to an operable status, providing additional training on the use of human error prevention techniques, and providing additional training on the instrument inverters.

.3 22 Battery Charger Rendered Inoperable During Maintenance on 22 Inverter

a. Inspection Scope

The inspectors reviewed licensee procedures, TS, operations logs, WO 380762, "22 Inverter Synch Lamp is Out – Adjust Frequency," and the human performance investigation report to determine the circumstances that led to rendering the 22 battery charger inoperable on April 26, 2009.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

Introduction: A self-revealed Green finding and an NCV of TS 5.4.1 were identified on April 26, 2009, due to maintenance personnel failing to implement procedures which control safety-related equipment. Specifically maintenance personnel did not comply with work order instructions or procedures rendering the 22 battery charger inoperable during the performance of maintenance on the 22 inverter.

Description: On April 26, 2009, maintenance personnel were performing work on the 22 inverter using WO 380762. As part of this WO, maintenance personnel were instructed to install test loads onto the inverter. Prior to installing the test loads, the maintenance workers became concerned for their personal/industrial safety when they found that the areas immediately around the load termination connections were energized. Although the WO clearly stated that the maintenance activity would be performed in the vicinity of energized equipment, the maintenance workers reviewed procedures included with the WO and concluded that they could manipulate additional breakers to improve the industrial safety of the work area. To do this, the workers intended to open the breaker for the 22 inverter; the 22 battery charger breaker was opened by mistake. Following this action, the maintenance workers tested components in the area to make sure they were de-energized. Upon receiving indications that the components remained energized, the maintenance workers reviewed their actions and found that the wrong breaker had been opened. The maintenance workers did not stop and contact the control room after identifying this error. Instead, the workers closed the breaker for the 22 battery charger and opened the breaker for the 22 inverter. The control room operators contacted the maintenance workers to determine the cause of multiple alarms received in the control room. Following this discussion, licensee management initiated a stop work order for this maintenance activity.

The inspectors reviewed the work plan for WO 380762. Step 5.4 of the work plan stated that the plan was required to be returned to maintenance planning if any changes were needed to address industrial safety issues. This was not done. In addition, the maintenance workers failed to use an approved procedure during the manipulation of the 22 battery charger breaker. The inspectors reviewed the licensee's human performance investigation report for this event and found that the pre-job briefing for this maintenance activity failed to include adequate detail on the potential consequences of the maintenance activity. The work plan also failed to include adequate detail regarding the specific sections of other procedures to be used during the maintenance activity.

Analysis: The inspectors determined that rendering the 22 battery charger inoperable during the performance of maintenance activities was a performance deficiency that impacted the Mitigating Systems cornerstone and required evaluation using the SDP. The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function of one train of equipment for greater than the TS allowed outage time, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Practices area because maintenance personnel did not follow procedures during this maintenance activity (H.4(b)).

Enforcement: Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 9, requires that maintenance that can affect the performance of safety-related equipment be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstance.

Contrary to the above, on April 26, 2009, maintenance personnel failed to perform safety-related maintenance on the 22 inverter using written procedures and work instructions appropriate to the circumstance. Specifically, maintenance workers manipulated plant equipment to improve the industrial safety of the work area without using a procedure. In addition, the WO instructions stated that changes to the work WO to improve industrial safety were required to be made by maintenance planning personnel. The unapproved and unproceduralized actions of the maintenance individuals resulted in rendering the 22 battery charger inoperable for approximately 2 minutes. Because this finding was of very low safety significance, and because it was entered into the CAP as CAP 1179638, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy (NCV 05000306/2009003-06). Corrective actions for this issue included issuing a stop work order and remediating the maintenance workers on human performance tool use.

.4 122 Air Compressor Rendered Non-Functional During Performance of Independent Verification Activities

a. Inspection Scope

The inspectors reviewed licensee procedures, operations logs, and the human performance investigation report to determine the circumstances that led to rendering the 122 air compressor non-functional on April 30, 2009.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

Introduction: A self-revealed Green finding was identified on April 30, 2009, due to operations personnel failing to implement procedures which control plant equipment. Specifically operations personnel operated the incorrect component, rendering the 122 air compressor non-functional during the performance of independent verification activities.

Description: On April 30, 2009, an operator was assigned to independently verify that the breaker for the 121 air compressor (breaker 111E-6, 1A1-B4) had been left in the off position as part of a clearance order final clear checklist. Prior to performing the independent verification activity, the operator was provided a detailed pre-job brief. After the operator entered the air compressor room, he proceeded to the motor control center and located the breaker that he believed required independent verification. The operator immediately recognized that the breaker he had located was in the on position rather than the off position. Although all plant personnel were trained to stop when unexpected plant conditions were encountered, the operator assumed that the clearance order tag remover had not correctly positioned the breaker. In addition, the operator failed to compare the breaker number of the breaker he had located against the breaker number listed on the final clear checklist. These errors resulted in the operator opening breaker 121E-6, 1A2-B4 (the breaker for the 122 air compressor) instead of verifying that breaker 111E-6, 1A1-B4 (the breaker for the 121 air compressor) had been left in the off position. After performing this action, the operator heard the 122 air compressor begin to shut down. Rather than calling the control room to inform the operators what had happened, the operator inappropriately shut breaker 121E-6, 1A2-B4 to restore the 122 air compressor to a functional status.

The inspectors reviewed the licensee's human performance investigation report and procedures related to the performance of clearance order activities. The inspectors determined that the operator's manipulation of plant equipment outside of normal processes was prohibited by FP-OP-COO-01, "Conduct of Operations." This procedure also required the use of self checking for all equipment manipulations.

Analysis: The inspectors determined that failing to implement procedures which control plant equipment rendering the 122 air compressor non-functional during the performance of clearance order activities was a performance deficiency that impacted the Mitigating Systems cornerstone and required evaluation using the SDP. The inspectors determined that this finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding was determined to be of very low safety significance because it was not a design deficiency, did not result in a loss of system safety function, was not an actual loss of safety function for one or more non-TS trains of equipment for greater than 24 hours, and did not screen as a potentially significant seismic, flooding, or severe weather issue. The inspectors concluded that this finding was cross-cutting in the Human Performance, Decision Making area because the operator failed to use conservative assumptions when making the decision regarding the need to operate breaker 121E-6, 1A2-B4 (H.1(b)) (FIN 05000282/2009003-07; 05000306/2009003-07).

Enforcement: No violations of NRC requirements were identified due to the air compressors being non-safety related. The licensee initiated CAP 1180343 to document this issue. Corrective actions for this issue included restoring the 122 air compressor to a functional status and briefing operations personnel on the details/lessons learned from this event

.5 Unit 2 Transient During Turbine Stop Valve Testing

a. Inspection Scope

The inspectors interviewed personnel and reviewed CAPs, procedures, training lesson plans, and operator logs to identify the cause of a transient during the performance of Unit 2 turbine stop valve testing on May 9, 2009. Documents reviewed in this inspection are listed in the Attachment.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

Introduction: A self-revealed Green finding was identified on May 9, 2009, due to operations personnel failing to ensure that procedures used to test the Unit 2 turbine stop valves provided adequate guidance regarding the valve position limiter setting. The failure to ensure that adequate guidance was provided prior to performing the turbine stop valve test resulted in an RCS transient and a seven percent reduction in reactor power.

Description: On May 9, 2009, operations personnel were preparing to perform SP 2054, "Turbine Stop, Governor, Reheat Stop and Reheat Intercept Valve Exercise." Prior to performing this test, operations personnel had lowered Unit 2 reactor power in accordance with Operating Procedure 2C1.4, "Unit 2 Power Operation," to allow the condenser water boxes to be cleaned.

During the pre-job briefing for SP 2054, operations personnel identified that this was the first time that the crew had performed this SP since the installation of the digital electro-hydraulic control (EHC) system. Based upon this information, the operating crew took additional time to review SP 2054, the digital EHC equipment, operating experience, and the applicable abnormal operating procedures.

Following the pre-job brief, additional operating experience regarding the need to move control rods to minimize temperature swings during the SP was discussed. This discussion led to an additional review of Abnormal Operating Procedure 2C23 AOP2, "Malfunction of Turbine EH [Electro-Hydraulic] Control System," and questioning the need to lower the setting on the valve position limiter. The crew performed an additional review of 2C1.4 and found that Step 3.5 stated the following:

> If the turbine is to be operated at a given load for an extended period of time, the valve position limiter should be lowered until the "valve position limit" signal is at or close to the "current valve demand" signal. This should prevent or minimize turbine control valve operations.

However, SP 2054 was silent regarding the need to adjust the valve position limiter setting prior to performing the turbine stop valve test.

Although the operators recognized that the procedures discussed above lacked sufficient guidance, they failed to consult other knowledgeable individuals or look at design basis or training information to ensure sufficient guidance was provided prior to performing SP 2054. Instead, the operators discussed how they believed the valve position limiter and the EHC system worked and made decisions regarding how to operate the plant, and how to perform the test, based upon what they thought to be true rather than what they confirmed to be true through a review of design basis documents. This resulted in improperly lowering the valve position limiter prior to performing the test. The failure to ensure that the valve position limiter was properly set prior to performing SP 2054 resulted in an unexpected RCS transient. Specifically, operations personnel noted significant changes in RCS average temperature, pressurizer pressure, and reactor power. In addition, operations personnel entered TS 3.4.1, Condition A, for one minute due to the RCS departure from nuclear boiling pressurizer pressure parameter not being within the limits specified in the Core Operating Limits Report.

Analysis: The inspectors determined that the failure to ensure that adequate guidance regarding the valve position limiter setting existed prior to performing SP 2054 was a performance deficiency, because licensee Procedure FP-G-Doc-3, "Procedure Use and Adherence," requires that procedures be adequate to perform evolutions and testing. The Finding impacted the Initiating Events cornerstone and required an evaluation using the SDP. The inspectors determined that this finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone. In addition, the finding affected the cornerstone objective of limiting the likelihood of events that upset plant stability during power operations. The inspectors concluded that this finding was of very low safety significance because it did not result in exceeding the TS limit on RCS leakage, did not result in a total loss of safety function of a mitigating system, did not contribute to both the likelihood of a reactor trip and that mitigating systems equipment would not be available, and it did not increase the likelihood of a fire or flood (FIN 05000306/2009003-08). The inspectors determined that this finding was cross-cutting in the Human Performance, Decision Making area because operations personnel failed to use conservative assumptions in deciding how the valve position limiter operated. In addition, operations personnel failed to demonstrate that their proposed actions regarding the valve position limiter setting was safe (by reviewing design basis or training documents and/or requesting assistance from additional personnel) prior to performing the test (H.1(b)).

Enforcement: No violation of NRC requirements was identified due to the EHC system and the turbine stop valves being non-safety related. The licensee initiated CAP 1181513 to document this issue. Corrective actions for this issue included revising SP 2054 and the corresponding Unit 1 SP to ensure that guidance regarding the valve position limiter was adequate, providing additional training on the digital EHC system to operations personnel, and re-enforcing the human performance fundamentals.

.6 High Vibration on 21 Component Cooling Water Pump

a. Inspection Scope

The inspectors talked with licensee personnel and reviewed procedures, WOs, vendor manual information and control room logs to determine the circumstances surrounding the need to shut down the 21 CC pump on April 22, 2009. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

A licensee identified NCV is discussed in Section 4OA7 of this inspection report.

.7 D5 and D6 Emergency Diesel Generator Damper Failures

a. Inspection Scope

The inspectors discussed the recent failure of two emergency diesel generator ventilation system dampers with operations and engineering personnel. In addition, the inspectors reviewed the licensee's Apparent Cause Report documented as CAP Item 1178685-03. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

A licensee identified NCV is discussed in Section 4OA7 of this report.

.8 Unexpected Pressurizer Backup Heater Initiation During Pressurizer Level Controller Calibration

a. Inspection Scope

The inspectors discussed this event with operations personnel and reviewed the licensee's response to CAP 1174731. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153-05.

b. Findings

No findings of significance were identified.

.9 (Closed) LER 05000282/07-004-02: Technical Specification Required Shutdown Due to Both Emergency Diesel Generators Being Inoperable

This licensee submitted this LER supplement following questioning by the inspectors regarding whether this issue constituted a safety system functional failure. The licensee reviewed this issue and determined that a safety system functional failure had occurred. The inspectors reviewed this LER, and the PI data, and verified that the licensee had included the safety system functional failure as part of their updated PI information. No additional findings of significance were identified. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

.10 <u>(Closed) LER 05000306/08-001-01: Unanalyzed Condition Due to Both Trains of Component Cooling Water Being Susceptible to a Postulated High Energy Line Break</u>

The licensee submitted this LER supplement following questioning by the inspectors regarding whether this issue constituted a safety system functional failure. The licensee reviewed this issue and determined that a safety system functional failure had occurred. The inspectors reviewed this LER, and the PI data, and verified that the licensee had included the safety system functional failure as part of their updated PI information. No additional findings of significance were identified. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

.11 <u>(Closed) LER 05000306/09-001-00: Clearance Order Renders Opposite Train Emergency Diesel Generator Inoperable</u>

On February 16, 2009, at 1:29 a.m., the licensee removed the D5 EDG from service for planned maintenance. In order to perform the maintenance safely, the licensee opened the main control power breaker for the EDG. The licensee knew that opening this breaker would prevent the D5 fuel oil transfer pumps from starting automatically. However, operations personnel believed that the manual start capability for the D5 fuel oil transfer pumps would remain available. The ability to manually start the D5 fuel oil transfer pumps was needed to ensure that the fuel oil available to the D6 EDG was greater than TS requirements. Approximately 34 hours later, the licensee discovered that the clearance order used for the D5 EDG maintenance prevented operations from manually starting the D5 fuel oil transfer pumps. The licensee removed the clearance and returned the D5 fuel oil transfer pumps to service approximately 45 minutes later.

The inspectors reviewed this issue and determined that although a performance deficiency and a violation had occurred, the performance deficiency was of very low safety significance and the violation was licensee identified. As a result, the enforcement actions associated with this event are documented in Section 4OA7 of this inspection report.

This event follow-up review constituted one sample as defined in IP 71153-05.

.12 <u>(Closed) LER 05000282/09-002-00: Unplanned Safety Related Actuation of 121 Cooling Water Pump</u>

This issue was discussed in Section 1R19.1 of this inspection report. A self-revealed Green finding and an NCV of 10 CFR Part 50, Appendix B, Criterion V were identified. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

4OA5 Other Activities

.1 OpESS 2007-03, Revision 2, Crane and Heavy Lift Inspection, Supplemental Guidance for IP-71111.20

a. Inspection Scope

On June 15, 2009, the inspectors performed inspections using OpESS 2007-03, Revision 2, “Crane and Heavy Lift Inspection,” related to the reactor vessel head removal and installation activities conducted during refueling outages. The inspection included a review of the following:

- The licensee’s responses to GL 80-113 and GL 81-07;
- Documentation regarding the designation of the polar crane, i.e., whether “single-failure-proof,” evaluated as equivalent to “single-failure-proof,” or neither;
- Polar crane preventative maintenance, testing, and inspection procedures;
- The reactor vessel head drop analysis and supporting calculations;
- Calculations for special lifting devices associated with lifting the reactor vessel head;
- Procedures used to determine whether the reactor vessel head maximum lift height and medium are bounded by the licensee’s rector vessel head drop analysis;
- The licensee’s engineering evaluation of NEI 08-05, “Industry Initiative on Control of Heavy Loads;” and
- Qualification and training of riggers, crane operators, and electrical maintenance personnel assigned to work on the polar cranes.

b. Findings

No findings of significance were identified.

.2 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee 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.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 9, 2009, the inspectors presented the inspection results to Mr. M. Wadley and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- On June 5, 2009, the inspectors presented inspection results for the radiation protection inspection to Mr. K. Ryan and other members of the licensee staff. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

- On July 21, 2009, the inspectors presented inspection results for the operating experience inspection on cranes and the movement of heavy loads to Mr. R. Womack and other members of the licensee's staff. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violations of very low 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.

Cornerstone: Mitigating Systems

- Title 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality be prescribed by instructions, procedures, and drawings appropriate to the circumstance. Contrary to the above, on May 22, 2009, the licensee determined that work instructions used to install the 21 CC pump bearings were not appropriate to the circumstance. The finding was determined to be of very low safety significance, because the 21 CC pump was not inoperable for greater than the TS allowed time. The licensee documented this issue in CAP 1179272. Corrective actions for this issue included replacing the 21 CC pump inboard bearing and revising the bearing installation instructions.

- Title 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality be prescribed by instructions, procedures, and drawings appropriate to the circumstance. Contrary to the above, on March 29 and April 18, 2009, the licensee failed to have procedures appropriate to the circumstance to ensure that periodic maintenance on the D5 and D6 EDG ventilation dampers was performed. The finding was determined to be of very low safety significance, because the dampers did not cause the EDG to be inoperable for greater than the TS allowed time. This issue was documented in

CAPs 1175563 and 1178658. Corrective actions for this issue included returning the ventilation dampers to service and implementing preventive maintenance procedures to address damper alignment issues.

- Technical Specification 3.8.3.D states that the emergency diesel generators shall be declared inoperable immediately if the stored diesel generator fuel oil supply for Unit 2 is less than 65,000 gallons.

  Technical Specification 3.8.1.E states that if both emergency diesel generators are inoperable, one emergency diesel generator must be returned to an operable status within 2 hours.

  Technical Specification 3.8.1.F states that if one emergency diesel generator cannot be returned to an operable status within two hours, the reactor must be placed in Mode 3 within 6 hours and in Mode 5 within 36 hours.

  Contrary to the above, between February 16, 2009, and February 18, 2009, the licensee failed to declare the D6 EDG inoperable when the stored diesel generator fuel oil supply dropped below 65,000 gallons. Although the licensee had removed the D5 EDG from service for maintenance, they were unaware that the clearance order activities associated with this maintenance had resulted in rendering the D6 EDG inoperable. Because the condition of the D6 EDG was not known, the licensee failed to return an EDG to an operable status within 2 hours. In addition, actions were not taken to place Unit 2 in Mode 3 and Mode 5 as required by the TSs. The licensee initiated CAP 1169735 to document this issue and submitted LER 05000306/09-001. The finding was determined to be of very low safety significance due to the short amount of time that both of the EDGs were inoperable and because the probability of an external flood in mid-February was extremely low. Corrective actions included returning the D6 EDG to an operable status, revising the clearance order tagging sheet, providing additional oversight for complicated electrical clearance orders, and providing additional electrical print reading training to selected operations personnel.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Wadley, Site Vice President
B. Sawatzke, Director Site Operations
K. Ryan, Plant Manager
J. Anderson, Regulatory Affairs Manager
L. Clewett, Business Support Manager
B. Flynn, Safety and Human Performance Manager
R. Hite, Radiation Protection and Chemistry Manager
D. Kettering, Site Engineering Director
J. Lash, Operations Manager
R. Madjerich, Production Planning Manager
J. Muth, Nuclear Oversight Manager
S. Northard, Performance Improvement Manager
M. Schmidt, Maintenance Manager
J. Sternisha, Training Manager

Nuclear Regulatory Commission

J. Giessner, Reactor Projects Branch 4 Chief
T. Wengert, Office of Nuclear Reactor Regulation Project Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000282/2009003-01; 05000306/2009003-01	URI	Potential Turbine Building Flooding Issue (Section 1R06)
05000282/2009003-02; 05000306/2009003-02	NCV	Failure to Positively Control Compensatory Measures (Section 1R15.1)
05000282/2009003-03	NCV	Failure to Maintain Control of Unit 1 Containment Personnel Airlock Configuration (Section 1R15.1)
05000282/2009003-04; 05000306/2009003-04	NCV	Failure to Control Maintenance Activities to Ensure Plant Equipment is Not Unnecessarily Challenged (Section 1R19.1)
05000306/2009003-05	NCV	23 Inverter Rendered Inoperable During Training Activities (Section 4OA3.2)
05000306/2009003-06	NCV	22 Battery Charger Rendered Inoperable During Maintenance on 22 Inverter (Section 4OA3.3)
05000282/2009003-07; 05000306/2009003-07	FIN	122 Air Compressor Rendered Non-Functional During Clearance Order Activities (Section 4OA3.4)
05000306/2009003-08	FIN	Failure to Ensure Turbine Valve Testing Procedure was Adequate (Section 4OA3.5)

Closed

05000282/2009003-02; 05000306/2009003-02	NCV	Failure to Positively Control Compensatory Measures
05000282/2009003-03	NCV	Failure to Maintain Control of Unit 1 Containment Personnel Airlock Configuration
05000282/2009003-04; 05000306/2009003-04	NCV	Failure to Control Maintenance Activities to Ensure Plant Equipment is Not Unnecessarily Challenged
05000306/2009003-05	NCV	23 Inverter Rendered Inoperable During Training Activities
05000306/2009003-06	NCV	22 Battery Charger Rendered Inoperable During Maintenance on 22 Inverter
05000282/2009003-07; 05000306/2009003-07	FIN	122 Air Compressor Rendered Non-Functional During Clearance Order Activities
05000306/2009003-08	FIN	Failure to Ensure Turbine Valve Testing Procedure was Adequate
05000282/07-004-02	LER	Technical Specification Required Shutdown Due to Both Emergency Diesel Generators Being Inoperable
05000306/08-001-01	LER	Unanalyzed Condition Due to Both Trains of Component Cooling Water Being Susceptible to a Postulated High Energy Line Break
05000306/09-001-00	LER	Clearance Order Renders Opposite Train Emergency Diesel Generator Inoperable
05000282/09-002-00	LER	Unplanned Safety Related Actuation of 121 Cooling Water Pump

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors 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.

1R01 Adverse Weather

- Abnormal Procedure AB-4; Flood; Revision 33
- Daily Mississippi River Level Predictions; March 27 through April 4, 2009
- List of Open Work Requests and Work Orders on Screenhouse Ventilation System; no date provided
- CAP 1174370; No Tornado Protection for Component Cooling Water Piping to the 122 Spent Fuel Pool Heat Exchanger; March 23, 2009
- OPR 1174370-01; Operability Review for CAP 1174370; March 24, 2009
- ACE 1174370-08; Apparent Cause Evaluation for CAP 1174370; June 11, 2009
- Abnormal Procedure AB-2; Tornadoes, Thunderstorms, and High Winds; Revision 33
- Temporary Procedure Change Request 033B; Add Steps to AB-2; May 22, 2009
- Procedure 1C14 AOP 1; Loss of Component Cooling Water; Revision 16

1R04 Equipment Alignment

- CAP 1176673; 22 Diesel-Driven Cooling Water Pump Suction End Bell Bearing Water Supply Line Broken; April 3, 2009
- CAP 1024213; Unit 1 Reactor Tripped After Losing 50 Percent Feedwater Flow; April 14, 2006
- CAP 1061790; Feedwater Support Baseplate Anchor Bolt Stressed Higher Than Stress Allowables; November 15, 2006
- CAP 1100947; Develop an a(1) Action Plan for 12 Main Feedwater Pump; July 10, 2007
- CAP 1128868; Feedwater Isolation Relay Did Not Energize; February 27, 2008
- CAP 1038407; 11 Auxiliary Feedwater Pump is at 95 Percent of its Unavailability; July 5, 2006
- CAP 1051672; Develop an a(1) Action Plan for the Auxiliary Feedwater System; September 22, 2006
- Open WOs on the Feedwater System; no date provided
- Procedure H54; Motor Program; Revision 1
- CAP 1090699; High Vibration on 12 Main Feedwater Pump; May 3, 2007
- Integrated Checklist C1.1.35-1; Cooling Water System Unit One; Revision 10
- Integrated Checklist C1.1.35-3; Cooling Water System; Revision 28
- Integrated Checklist C1.1.20.7-5; D2 Diesel Generator Valve Status; Revision 20
- Integrated Checklist C1.1.20.7-6; D2 Diesel Generator Auxiliaries and Room Cooling Local Panels; Revision 10
- Integrated Checklist C1.1.20.7-7; Diesel Generator D2 Main Control Room Switch and Indicating Light Status; Revision 13
- Integrated Checklist C1.1.20.7-8; D2 Diesel Generator Circuit Breakers and Panel Switches; Revision 16
- System Prestart Checklist C16-1; Spent Fuel Pool Cooling; Revision 14

1R05 Fire Protection

- Fire Hazards Analysis
- ICPM 0-001; Fire Detection Zone Detector Calibration/Repair; Revision 13
- Procedure F5, Appendix A; Fire Plan Maps; Various Revisions
- Safe Shutdown Analysis
- SP 1189; Safety Related Fire Detector Check; Revision 24
- SP 2106; Fire Panel 70466 Detector Sensitivity Check; Revision 7
- SP 2107B; D5/D6 Fire Detection Test of Non-Trip Devices; Revision 5
- WO 304768; SP 2107B - D5/D6 Fire Detection Test of Non-Trip Devices; June 1, 2007
- WO 328262; SP 2107B - D5/D6 Fire Detection Test of Non-Trip Devices; November 27, 2007
- WO 339758; SP 2107B - D5/D6 Fire Detection Test of Non-Trip Devices; May 30, 2008
- WO 345167; SP 1189 - Safety Related Fire Detector Check; July 30, 2008
- WO 354105; SP 2107B - D5/D6 Fire Detection Test of Non-Trip Devices; December 4, 2008
- WO 356328; SP 1189 - Safety Related Fire Detector Check; January 10, 2009
- WO 360229; SP 2106 - Fire Panel 70466 Detector Sensitivity Check; February 18, 2009

1R06 Flooding

- Abnormal Operating Procedure C35 AOP2; Loss of Pumping Capacity or Supply Header Without Safety Injection; Revision 11
- Administrative Work Instruction 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 4
- CAP 1178236; No HELB Flooding Calculation for the Turbine Building; April 15, 2009
- CAP 1179019; Actions from Operating Experience Review 888906 Have Not Been Completed; April 21, 2009
- CAP 888906; Response to Internal Flood Design Deficiencies Operating Experience; September 21, 2005
- GAR 830732; Determine the Effects of Potential Flooding in the Turbine Building; April 8, 2005
- Letter from A. Giambusso, Atomic Energy Commission to A.V. Dienhart, Northern States Power Company; December 12, 1972
- Letter from A.V. Dienhart, Northern States Power Company to R.C. DeYoung, Atomic Energy Commission; October 23, 1972
- Letter from D.J. Skovholt, Atomic Energy Commission to A.V. Dienhart, Northern States Power Company; Flooding of Critical Equipment; August 3, 1972
- Letter from R.C. DeYoung, Atomic Energy Commission to A.V. Dienhart, Northern States Power Company; September 26, 1972
- NRC Information Notice 2005-30; Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design; November 7, 2005
- Operability Recommendation 1178236; Review Impact of Missing Analyses on Turbine Building; Revision 0
- Procedure F9; High Energy Line Break/Leak; Revision 8
- Procedure H36; Plant Flooding; Revision 1
- TP 13998; Verify Physical Inputs to Internal Flooding Evaluations; Revision 1

1R12 Maintenance Effectiveness

- CAP 0122168; Evaluate Maintenance on Instrument Air Compressor Air Receivers Against Maintenance Rule; December 26, 2007
- CAP 1038833; Top 10 Equipment List Addition: Air Compressors; July 7, 2006
- CAP 1074007: 122 Air Compressor Moisture Separator Excessive Water and Dirt; January 25, 2007

- CAP 1074957; Safety Injector Bistable Found O.O.T.; January 31, 2007
- CAP 1086219; During Performance of SP 2032A U2 Experienced a Train A Actuation; April 5, 2007
- CAP 1088358; 122 Instrument Air Compressor at 65% of the Unavailability Performance Criteria; April 18, 2007
- CAP 1088365; 123 Instrument Air Compressor at 65% of the Unavailability Performance Criteria; April 18, 2007
- CAP 1092308; Unit 1, Pressurizer Pressure High Bistable Failure; May 12, 2007
- CAP 1092494; Unit 2 Reactor Protection at 54% of its Unavailability Performance Criteria; May 14, 2007
- CAP 1093611; Reactor Protection Bistable Toggling Tripped/Not Tripped; May 22, 2007
- CAP 1094203; Corrective Actions from Unit 2 Root Cause Evaluation; May 26, 2007
- CAP 1097384; 121 Air Compressor Tripped Off; June 19, 2007
- CAP 1099269; Bistable 2FC-413 Was Found Out of Tolerance During SP 2003; June 26, 2007
- CAP 1100534; Evaluate CAP 1086219 Against Plant Level Performance Criteria; July 5, 2007
- CAP 1110071; Service Air a(1) Action Plan Does Not Include Corrective Actions from Root Cause Evaluation; September 5, 2007
- CAP 1118585; Short Term Actions to Improve Air Compressor Reliability; November 19, 2007
- CAP 1122168; Evaluate Maintenance on Instrument Air Compressor Air Receivers Against Maintenance Rule; December 26, 2007
- CAP 1127638; Flow Transmitter 1FT-415 Found Out of Spec On SP 1002B; February 17, 2008
- CAP 1128082; 123 Instrument Air Compressor at 89% of MR Unavailability; February 20, 2008
- CAP 1128082; 123 Instrument Air Compressor at 89% of MR Unavailability Performance Criteria; February 20, 2008
- CAP 1128868; Feedwater Isolation Relay 1F-30-X1 Did Not Energize During SP 1547; February 27, 2008
- CAP 1145953; Red Channel Set Point Failed Low Causing Reactor Trip; July 31, 2008
- CAP 1150807; Foreign Material Discovered in 122 Air Compressor After Cooler Outlet Check Valve; September 16, 2008
- CAP 1151320; Generate a(1) Action Plan for 123 Air Compressor; September 20, 2008
- CAP 1151320; Generate An a(1) Action Plan for 123 Air Compressor; September 20, 2008
- CAP 1156103; Service Air Exceeds Maintenance Rule Performance Criteria; October 29, 2008
- CAP 1156628; Recalculate Station Air Performance Criteria; October 23, 2008
- CAP 1164329; 121 Air Compressor Tripped Off; January 4, 2009
- CAP 1164427; 121 Air Compressor Motor; January 5, 2009
- CAP 1165340; 121 Instrument Air Dryer and Purifier Malfunction; January 13, 2009
- CAP 1167652; 122 Air Compressor Failed to Start When Placed in Preferred; February 1, 2009
- CAP 1167727; Unexpected LCO Entry; February 2, 2009
- CAP 1171039; 123 Compressor Damaged Components; February 26, 2009
- CAP 1175697; 121 Air Compressor Tripped; March 30, 2009
- CAP 866960; Top Ten Equipment List Addition- Foxboro H-Line; July 15, 2005
- Maintenance Rule a(1) Action Plan for the Reactor Protection System F Delta Q Controllers; Revision 2;
- Maintenance Rule a(1) Action Plan: Station Air; Revision 4;
- Monthly Maintenance Rule Performance Report; March 2009;
- Reactor Protection Maintenance Rule Program Basis Document; Revision 13;
- Reactor Protection System Risk Significant Equipment Performance Monitoring; Revision 0

- Station Air Maintenance Rule Program Basis Document; Revision 13;
- Station Air System Risk Significant Equipment Performance; Revision 2;

1R13 Maintenance Risk Assessment and Emergent Work

- C20.3 AOP10; Electric Power System Operating Restrictions and Limitations on Loss of 345 kV Bus 1; Revision 7
- EOOS Risk Monitoring Program
- Operations Logs for 121 Traveling Screen; May 13-14, 2009

1R15 Operability Evaluations

- Abnormal Operating Procedure C35 AOP2; Loss of Pumping Capacity or Supply Header Without Safety Injection; Revision 11
- Administrative Work Instruction 5AWI 8.9.0; Internal Flooding Drainage Control; Revision 4
- Apparent Cause Evaluation 1166911-01; D1 Lube Oil Cooler Tube Leak; March 13, 2009
- Apparent Cause Evaluation 1174897-04 and -05; Unit 1 Containment Personnel Airlock Unsecured; April 27, 2009
- CAP 1174897; Unplanned Entry in Technical Specification 3.6.2 Condition A; March 25, 2009
- CAP 1179019; Actions from Operating Experience Review 888906 Have Not Been Completed; April 21, 2009
- CAP 1179979; Unit 2 Turbine Building Roll-up Door Found at 14 Inches Open; April 28, 2009
- CN-PAFM-08-10; Prairie Island Units 1 and 2 Surge Line Analysis; May 28, 2008
- Control Room Security Reader Transaction History; March 25, 2009
- ENG-CS-380; Comparison of As-Found Restraint Gaps to Required Gaps for the Unit 2 Pressurizer Surge Line; Revision 1
- Engineering Change 14216; Evaluation of Approach Canal Hydrographic Survey Results – Pre-Dredging; Revision 0
- Engineering Evaluation 14364; D1 EDG Lube Oil Cooler Tube Leak Vendor Evaluation; June 25, 2009
- FP-OP-COO-01; Conduct of Operations; Revision 5
- FP-OP-OL-01-PI; Operability/Functionality Determination (Prairie Island Only); Revision 0
- Letter from A. Giambusso, Atomic Energy Commission to A.V. Dienhart, Northern States Power Company; December 12, 1972
- Letter from A.V. Dienhart, Northern States Power Company to R.C. DeYoung, Atomic Energy Commission; October 23, 1972
- Letter from D.J. Skovholt, Atomic Energy Commission to A.V. Dienhart, Northern States Power Company; Flooding of Critical Equipment; August 3, 1972
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- Operability Recommendation 1178236; Review Impact of Missing Analyses on Turbine Building; Revision 0
- Operational Logs; March 25, 2009
- Procedure F9; High Energy Line Break/Leak; Revision 8
- Procedure H36; Plant Flooding; Revision 1
- SP 1132; Unit 1 Personnel And Maintenance Airlock Door Seal Test; Revision 37

- Structural Integrity Report 0900185.401; Failure Analysis of Diesel Generator Lube Oil Cooler Tube from Prairie Island; Revision 1
- Updated Safety Analysis Report
- Engineering Change 14499; Evaluation of Approach Canal Hydrographic Survey Results – Post Dredge; Revision 0

1R19 Post-maintenance Testing

- ACE 1167382/1174714; D1 Exhaust Manifold Fire; January 29, 2009
- ACE 1173880; Unplanned Safety Injection Actuation of 121 Motor-Driven Cooling Water Pump While Aligned for Safeguards Use; March 19, 2009
- CAP 1167382; Problems Encountered During D1 Fast Start Tests; January 29, 2009
- CAP 1173880; Autostart of 121 MDCLP During 12 DDCLP Testing; March 19, 2009
- CAP 1174714; D1 Diesel Inoperable Due to Fire and Jacket Coolant Leak; March 24, 2009
- D1 Emergent Schedule; March 25, 2009
- GMP 0HD-001; Heater Drain Pump Amplispeed Brush Replacement; Revision 1
- SP 1095; Bus 16 Load Sequencer Test; Revision 26
- SP 2035; D6 Diesel Generator Monthly Slow Start Test; Revision 30
- WO 311314-05; Replace Deficient Power Supply – Bus 16 Load Sequencer Cabinet; May 12, 2009
- WO 362382; SP 1093 D1 Diesel Generator Monthly Slow Start; March 23, 2009
- WO 365673; D6 Engines 1 And 2 – Perform Yearly Boroscope Inspection; February 17, 2009
- WO 367265; PM 3001-2-D1 Diesel Generator 24 Month Inspection; January 26, 2009
- WO 370918; 11 Heater Drain Tank Pump Replace Amplispeed Brush; April 15, 2009
- WO 380731; 11 Heater Drain Tank Pump Will Not Go Above 1410 RPM in Manual; May 5, 2009
- WO 381231; D1 Diesel Exhaust Manifold Fire; March 25, 2009
- WO 381232; D1 Diesel Jacket Coolant Leak Near Cylinder #7; March 28, 2009

1R20 Forced Outage

- 1C1.2; Unit 1 Startup Procedure; Revision 44
- 1C1.4; Unit 1 Power Operation; Revision 49
- 5AWI 3.1.1; Return to Power After Reactor Trip; Revision 15
- C1B; Reactor Startup; Revision 17
- FP-OP-PRC-01; Plant Operating Review Committee; Revision 6
- OI-09-106; Operating Information – Limitations While Operating at Reduced Power With 12 Circulating Water Pump OOS; no date provided
- OI-09-15; Operating Information – Delta I Limitations During Extended Operation at Reduced Power With 12 Circulating Water Pump OOS; no date provided

1EP6 Drill Evaluation

- CAP 1178133; DEP Failure – April 2009 Emergency Plan Drill; April 14, 2009
- CAP 1178136; Drill – Operations Support Center Failed to Meet Minimum Staffing for Radiation Protection Responders; April 14, 2009
- Prairie Island Nuclear Generating Plant April 14, 2009, Emergency Preparedness Drill Critique Report; May 13, 2009

4OA1 Performance Indicator Verification

- FP-PA-PI-02; NRC and WANO Performance Indicator Reporting; Revision 05
- H33.3; Safety System Functional Failures (SSFF) Performance Indicator Reporting Instructions; Revision 1
- H33; Performance Indicator Reporting; Revision 10
- Operator Logs (2Q2008 through 1Q2009)
- Prairie Island RCS Leakage and SSFF Performance Indicator Data (2Q2008 through 1Q2009)
- SP 1001AAA; Reactor Coolant System Leakage Investigation; Revision 13
- SP 2001AAA; Reactor Coolant System Leakage Investigation; Revision 8
- SWI-O-53; Operations Performance Indicator Reporting; Revision 4

4OA2 Identification and Resolution of Problems

- 2005 Generic Letter 89-13 Program Summary Review; no date provided
- 2006 Generic Letter 89-13 Program Summary Review; no date provided
- 2007 Generic Letter 89-13 Program Summary Review; no date provided
- Apparent Cause Report 1140901-01; Numerous Plugging/Fouling Problems Found; no date provided
- Apparent Cause Report 1179272-02; 21 CC Pump Inboard Bearing Vibrating; May 20, 2009
- CAP 1010606; Unit 2 Hypobromous Line Appears to be Plugged Again; January 16, 2006
- CAP 1025974; Hypobromous Replacement Keeps Getting Delayed; April 25, 2006
- CAP 1038105; Hypobromous Lines to 21 Cooling Water Pump Were Found Plugged; June 30, 2006
- CAP 1040309; Adverse Trend in the Ability to Add Oxidant to Cooling Water System; July 17, 2006
- CAP 1041927; Cooling Water System on Site Top 10 Equipment List; July 28, 2006
- CAP 1054147; Cooling Water Leak on the Supply Piping to Hypobromous; October 6, 2006
- CAP 1055632; Hypobromous Line to 21 Cooling Water Pump Plugged Again; October 13, 2006
- CAP 1074549; Hypochlorite Injection to 11 Cooling Water Pump Ruptured Diaphragm; January 29, 2007
- CAP 1084961; Unit 1 Hypobromous Skid Found Not Supplying Chemical; March 30, 2007
- CAP 1101902; Closed Cooling Water Systems Lacking Chemistry Focus; July 16, 2007
- CAP 1106914; Loss of Chlorine Chemical Injection to Unit 1; August 14, 2007
- CAP 1112166; Flow Blockages Found in Hypobromous System; September 19, 2007
- CAP 1121304; Unit 1 Hypobromous System Injection Line Plugged; December 15, 2007
- CAP 1143491; Complete Improvements in Sodium Hypobromous System; July 8, 2007
- CAP 1147366; Unable to Keep Unit 2 Cooling Water Chlorine In Spec; August 13, 2008
- CAP 1152650; Loss of All Chemical Treatment to Cooling Water System; September 29, 2008
- CAP 1152898; Delays in Fixing Top 10 Plant Health Issue of Chlorination; September 30, 2008
- CAP 1154003; Inspection of Unit 2 Circulating Water Bay Reveals Live Zebra Muscles; October 6, 2008
- CAP 1157602; Issues Related to Biofouling; October 31, 2008
- CAP 1162312; 122 Control Room Chilled Water Pump Has Pump Outboard Bearing High Vibrations; December 12, 2008
- CAP 1165438; Sampling of Closed Cooling Water Systems Not Performed; January 14, 2009
- CAP 1165787; Unit 2 Bleach Injection Quill Leak; January 17, 2009
- CAP 1166133; No Spare Parts for Hypobromous System; January 21, 2009

- CAP 1168499; Hypobromous Acid Feed System Shut Down Due to Leaks/Plugging; February 7, 2009
- CAP 1171241; Unplanned LCO Action Due to Bypassing 23 Inverter; February 27, 2009
- CAP 1175706; Vendor is Not Available to Support Cleaning Hypobromous System; March 20, 2009
- CAP 1175917; Potential Inadequate Resolution of Refueling Cavity Leakage Issue; March 31, 2009
- CAP 1175978; Biofouling Present in 121 Motor-Driven Cooling Water Pump Safeguards Bay Area; March 31, 2009
- CAP 1179019; Actions from Operating Experience Report 88906 Have Not Been Completed; April 21, 2009
- CAP 1179153; 21 CC Pump Bearing Plate Loose and Vibrating; April 22, 2009
- CAP 1179155; Excessive Vibration on 21 CC Pump Inboard Bearing; April 22, 2009
- CAP 1179272; Improper Bearing Fit Found on 21 CC Pump; April 23, 2009
- CAP 1179638; 22 Charger Inadvertently Turned Off; April 26, 2009
- CAP 1180343; 122 Air Compressor Inadvertently Turned Off; April 30, 2009
- CAP 1182603; Workers Entered Satellite RCA Without Electronic Dosimeters; May 19, 2009
- CAP 1183067; Ineffective Resolution of Diablo Canyon 4 Kilovolt Cable Degradation Issue; May 24, 2009
- CAP 1183142; Trend in Ineffective Resolution of Operating Experience Items; May 26, 2009
- CAP 1185859; Snapshot Self Assessment on Operating Experience; June 17, 2009
- CAP 285872; Plugging of the CH System; November 29, 2002
- CAP 738959; The Hypobromous System May Not Adequately Protect the Cooling Water System; August 6, 2004
- CAP 884646; Hypobromous Line to 21 Cooling Water Pump Plugged; September 8, 2005
- Equipment Improvement Request; October 20, 2008
- Generic Letter 89-13, Supplement 1; Service Water System Problems Affecting Safety Related Equipment; April 4, 1990
- Hypobromous to Bleach Only Treatment Plan; August 3, 2006
- Letter from Armand Masciatonio, NRC to T. M. Parker, Northern States Power; February 28, 1992
- Letter from Dominic C. DiIanni, NRC to T. M. Parker, Northern States Power; March 15, 1990
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- Letter from T. M. Parker, Northern States Power to the Nuclear Regulatory Commission; January 28, 1992
- NRC Temporary Instruction 2515/159; Review of Generic Letter 89-13: Service Water System Problems Affecting Safety Related Equipment; July 29, 2004
- Procedure H21; Generic Letter 89-13 Implementing Program; Revision 13
- Radiation Protection Implementing Procedure RPIP 3050; Corrosion Monitoring and Control Program; Revision 11
- Request for Phased Approval; October 20, 2008

4OA3 Event Followup

- 1C1.4 AOP1; Rapid Power Reduction Unit 1; Revision 9
- 1F2502HS 12 Circulating Water Pump Forced Outage Schedule; May 20, 2009
- 21 CC Pump Inboard Bearing Vibration Data and Trends; April 22, 2009
- 2C1.4; Unit 2 Power Operation; Revision 44
- 2C23 AOP2; Malfunction of Turbine EH Control System; Revision 13
- Alarm Response Procedure C47511-301; 21 Steam Generator Level Deviation; Revision 21

- Alarm Response Procedure C47512-0508; Pressurizer High/Low Pressure; Revision 42
- Alarm Response Procedure C47513-0305; Auctioneered T-Average – T-Reference Deviation; Revision 42
- Apparent Cause Evaluation 1179272-02; 21 CC Pump Inboard Pump Bearing Vibrating; June 4, 2009
- Apparent Cause Evaluation 1181513-01; Operators Did Not Resolve Questions About Procedural Guidance Prior to Conducting Turbine Valve Testing; June 24, 2009
- C25; Circulating Water System; Revision 33
- C47001; Alarm Response Procedure – 12 Circ Water Pump Locked Out; Revision 15
- CAP 1086684; D5 EDG Recirculation Air Damper Failed to Open; April 9, 2007
- CAP 1109539; D5 and D6 Preventive Maintenance Optimization Review; August 30, 2007
- CAP 1154603; LER 2-08-01 May Need Rework; October 9, 2008
- CAP 1162013; LER 1-07-04 Requires Supplement; December 10, 2008
- CAP 1179153; 21 CC Pump Bearing Plate Loose and Vibrating; April 22, 2009
- CAP 1179155; Excessive vibration on 21 CC Inboard Pump Bearing; April 22, 2009
- CAP 1179272; Improper Bearing Fit Found on 21 CC Pump; April 23, 2009
- CAP 1179272-06; Maintenance Rework Evaluation – Improper Bearing Fit on 21 CC Pump; May 27, 2009
- CAP 557037; 22 D6 EDG Outside Air Motor Damper Actuator is Failed Open; December 11, 2003
- CAP 780488; 21 D5 EDG Exhaust Damper Won't Fully Close; November 29, 2004
- Emergency Response Computer System Plot; May 9, 2009
- General Maintenance Procedure GMP SOLI-001; Inverter Component Replacement and Calibration; Revision 1
- Human Performance Event Investigation Report for CAP 1171241; no date provided
- Maintenance Rule Evaluation 1175563-01; D6 Motor Damper Failed in Open Position; no date
- Maintenance Rule Evaluation; CAP 1179272; Improper Bearing Fit Found on 21 CC Pump; May 28, 2009
- MSPI Failure Determination; CAP 1179272; May 27, 2009
- NF-40119-1; Cable Tray System Unit 1 and 2 Screenhouse Ground Floor; Revision Q
- NF-40123-2; Underground Duct Runs – Screenhouse and Substation; Revision K
- Operating Procedure 2C20.8; Instrument AC Distribution System; Revision 18
- Operational Decision Making Document on Work Scope for 21 Component Cooling Water Pump; April 22, 2009
- PINGP 666; Event Notification 45077; May 18, 2009
- Pre-Job Briefing Sheet for SP 2054; May 7, 2009
- Reactor Trip - ERCS Data Plots
- Reactor Trip Report; May 21, 2009
- Site Clock Reset Red Sheet for CAP 1179638; no date provided
- SP 2054; Turbine Stop, Governor, Reheat Stop and Reheat Intercept Valve Exercise; Revision 38
- Station Stop Light Memo for Isolation of the 22 Battery Charger; no date provided
- Stoplight Memo; Unplanned LCO Entry on 23 Inverter due to Human Performance Error; February 28, 2009
- SWI O-39; Operations Training Plan; Revision 18
- Unit 2 Core Operating Limits Report for Cycle 25; Revision 0
- WO 362503; Exercise The Pressurizer Level Setpoint Controller ITC-401C; April 30, 2009
- WO 385069; Assist Xcel Underground With Cable Testing; May 18, 2009

4OA7 Licensee Identified Violations

- 21 CC Pump Inboard Bearing Vibration Data and Trends; April 22, 2009
- Apparent Cause Evaluation 1179272-02; 21 CC Pump Inboard Pump Bearing Vibrating; June 4, 2009
- CAP 1086684; D5 EDG Recirculation Air Damper Failed to Open; April 9, 2007
- CAP 1109539; D5 and D6 Preventive Maintenance Optimization Review; August 30, 2007
- CAP 1179153; 21 CC Pump Bearing Plate Loose and Vibrating; April 22, 2009
- CAP 1179155; Excessive vibration on 21 CC inboard Pump Bearing; April 22, 2009
- CAP 1179272; Improper Bearing Fit Found on 21 CC Pump; April 23, 2009
- CAP 1179272-06; Maintenance Rework Evaluation – Improper Bearing Fit on 21 CC Pump; May 27, 2009
- CAP 557037; 22 D6 EDG Outside Air Motor Damper Actuator is Failed Open; December 11, 2003
- CAP 780488; 21 D5 EDG Exhaust Damper Won't Fully Close; November 29, 2004
- Emergency Response Computer System Plot; May 9, 2009
- Maintenance Rule Evaluation 1175563-01; D6 Motor Damper Failed in Open Position; no date
- Maintenance Rule Evaluation; CAP 1179272; Improper Bearing Fit Found on 21 CC Pump; May 28, 2009
- Operational Decision Making Document on Work Scope for 21 Component Cooling Water Pump; April 22, 2009
- CAP 1187841; No Actions Taken for Failed Motor Damper 32427; July 1, 2009

LIST OF ACRONYMS USED

AC	Alternating Current
ALARA	As Low As Is Reasonably Achievable
APA	Apprentice Plant Attendant
APEO	Assistant Plant Equipment Operator
CAP	Corrective Action Program
CC	Component Cooling Water
CFR	Code of Federal Regulations
CH	Chemical Injection System
CL	Cooling Water System
DDCLP	Diesel-Driven Cooling Water Pump
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
GL	Generic Letter
HELB	High Energy Line Break
IP	Inspection Procedure
IR	Inspection Report
kV	Kilovolt
LER	Licensee Event Report
MDCLP	Motor-Driven Cooling Water Pump
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
PI	Performance Indicator
RCS	Reactor Coolant System
RO	Reactor Operator
RP	Radiation Protection
RWP	Radiation Work Permit
SDP	Significance Determination Process
SP	Surveillance Procedure
STA	Shift Technical Advisor
TS	Technical Specifications
TSO	Transmission System Operator
USAR	Updated Safety Analysis Report
WO	Work Order