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

May 6, 2015

Mr. Kevin Davison
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 05000282/2015001; 05000306/2015001

Dear Mr. Davison:

On March 31, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on April 9, 2015, with you and other members of your staff.

One NRC-identified and two self-revealed findings of very low safety significance (Green) were identified during this inspection. The findings were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of any NCV, 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 cross-cutting aspect assigned to 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.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

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

Enclosure:
IR 05000282/2015001; 05000306/2015001
w/Attachment: Supplemental Information

cc w/encl: Distribution via LISTSERV®

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50–282; 50–306; 72–010
License Nos:	DPR–42; DPR–60; SNM–2506
Report No:	05000282/2015001; 05000306/2015001
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	January 1, 2015 through March 31, 2015
Inspectors:	K. Stoedter, Senior Resident Inspector P. LaFlamme, Resident Inspector M. Bielby, Senior Operator Licensing Examiner J. Corujo-Sandin, Engineering Inspector N. Feliz-Adorno, Senior Engineering Inspector J. Havertape, Reactor Engineer L. Kozak, Senior Reactor Analyst J. Mancuso, Reactor Engineer V. Meghani, Reactor Engineer M. Ziolkowski, Reactor Engineer P. Zurawski, Senior Resident Inspector–Monticello
Approved by:	K. Riemer, Chief Branch 2 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

Inspection Report (IR) 05000282/2015001, 05000306/2015001; 01/01/2015–03/31/2015; Prairie Island Nuclear Generating Plant, Units 1 and 2; Operability Evaluations, Refueling and Outages and Event Followup.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors. Three findings were considered non-cited violations (NCVs) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated February 4, 2015. 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.

Cornerstone: Initiating Events

Green. A self-revealing finding of very low safety-significance and a non-cited violation of 10 CFR 50.49 was identified on March 5, 2015, for the licensee's failure to keep environmental qualification (EQ) files current and the failure to replace or refurbish EQ electrical equipment at the end of its designated life. Specifically, the licensee initiated CAP 1431268 in May 2014 to document numerous EQ file errors identified during an in-depth review of the EQ program. These file errors resulted in the EQ designated life for multiple safety-related solenoid valves being non-conservative such that some solenoids were installed beyond their designated life. Corrective actions included taking action to revise the incorrect EQ files and replacing the safety-related solenoids installed beyond their designated life.

The inspectors determined that this issue was more than minor because if left uncorrected the failure to maintain the EQ files and to replace or refurbish EQ equipment could result in a more significant safety concern. Specifically, the inaccurate files could result in EQ equipment not being refurbished or replaced as required. In addition, the failure to replace or refurbish EQ equipment installed beyond its designated life could result in equipment failure during normal operation or post-accident conditions. The inspectors utilized IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," and determined this issue was of very low safety significance because each of the questions provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," was answered "No." The inspectors concluded that this issue was cross-cutting in the Problem Identification and Resolution, Evaluation area because the licensee had not thoroughly evaluated CAP 1431268 to ensure that the resolution addressed the causes and extent of condition commensurate with the safety significance (P.2). (Section 4OA3.1)

Green. A self-revealing finding of very low safety significance and associated NCV of TS 5.4.1 was identified on December 19, 2014, due to the licensee's failure to follow Procedure FP–MA–FME–01, "Foreign Material Exclusion and Control." Specifically, workers failed to implement and adhere to the foreign material exclusion (FME) control requirements for a Level 1 foreign material exclusion area when replacing the Unit 1

reactor coolant pump (RCP) seals and associated piping during Refueling Outage 1R29. The failure to implement and adhere to the FME control requirements resulted in introducing foreign material into the reactor coolant system and the subsequent degradation of the #12 RCP seal in December 2014 and January 2015. The seal degradation led to two Unit 1 reactor shutdowns. Corrective actions for this issue included replacing the RCP seal, flushing the seal piping and establishing a process to review work document quality to ensure that appropriate programmatic requirements were included.

The inspectors determined that the failure to follow Procedure FP–MA–FME–01 was more than minor because it was associated with the equipment performance attribute of the Initiating Events cornerstone and impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors utilized Attachment 0609.04, “Initial Characterization of Findings,” and determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 1, “Initiating Events Screening Questions,” was answered “No.” The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Management area, because the organization failed to implement a process of planning, controlling, and executing work activities such that nuclear safety was the overriding priority. In addition, the work process failed to include the identification and management of risk commensurate to the work and the need for coordination with different groups or job activities (H.5). (Section 1R20.1)

Cornerstone: Barrier Integrity

Green. An inspector identified finding of very low safety significance and a NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," occurred on January 27, 2015, due to operations personnel failing to follow Procedure FP–OP–OL–01, “Operability/Functionality Determination,” while assessing the operability of the 14 containment fan coil unit (CFCU) and the Unit 1 containment. Specifically, personnel failed to perform an immediate operability determination for the 14 CFCU and the Unit 1 containment after the inspectors identified that the 14 CFCU was potentially leaking. Corrective actions for this issue included documenting the immediate operability determination after the inspectors brought this issue to the attention of the operations department and sharing the details of this event with other operations personnel.

The inspectors determined that the failure to perform an immediate operability determination on the 14 CFCU and the Unit 1 containment as required by Step 5.3.1 of Procedure FP–OP–OL–01 was more than minor because if left uncorrected, the failure to perform operability determinations, as required by procedure could result in incorrect/untimely operability conclusions and the failure to take action to correct degraded or deficient conditions, as required by the technical specifications (TS). In addition, this is the second example of an untimely CFCU operability determination identified by the inspectors in the last ten months. The inspectors utilized IMC 0609, Attachment 0609.04, “Initial Characterization of Findings,” and determined that this issue was of very low safety significance because each question provided in IMC 0609, Appendix A, Exhibit 3, “Barrier Integrity Screening Questions,” Part B, was answered “No.” The inspectors concluded that this finding was cross-cutting in the Human

Performance, Teamwork area because individuals and work groups failed to communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety was maintained (H.4). (Section 1R15.1)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at full power. On January 26, 2015, operations personnel shut down the Unit 1 reactor and entered a forced outage due to increased seal leakage from the 12 reactor coolant pump (RCP) seal. The Unit 1 reactor achieved criticality on February 11, 2015, following the replacement of the 12 RCP seal and flushing of seal related piping. On February 12, 2015, the main generator was synchronized with the electrical grid. Operations personnel completed their power ascension activities and returned Unit 1 to full power operation on February 13, 2015. Operations personnel took action to reduce Unit 1 reactor power to 90 percent on March 5, 2015, after a fuse failed in the heater drain tank pump control circuitry. The reactor was returned to full power operation following the fuse replacement. The Unit 1 reactor operated at full power conditions the remainder of the inspection period.

Unit 2 began the inspection period operating at full power. On March 5, 2015, operations personnel shut down the Unit 2 reactor following a valve failure that resulted in a loss of instrument air to containment. Subsequent events resulted in the licensee declaring a Notice of Unusual Event at 4:06 am on March 5 (see Section 4OA3 for details). The licensee also conducted a forced maintenance outage to address the cause of the valve failure and to perform additional maintenance. The Unit 2 reactor achieved critically at 4:45 am on March 25, 2015. The Unit 2 generator was synchronized to the electrical grid at 2:55 pm that afternoon. Operations personnel completed their power ascension activities and returned Unit 2 to full power operation on March 28, 2015. Unit 2 operated at full power the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

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:

- D6 emergency diesel generator (EDG);
- 11 reactor vessel gap support cooling system;
- D2 EDG; and
- Unit 1 containment fan coil unit (CFCU) system.

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, Updated Safety Analysis Report (USAR), Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of

ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted four partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

During the week of March 2, 2015, the inspectors performed a complete system alignment inspection of the 121 & 122 control room chiller system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings 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:

- Fire Area 26–D2 Diesel Generator Room;
- Fire Areas 101 &102–D5 & D6 Diesel Generator Rooms (695' elevation);
- Fire Areas 103 &104–D5 & D6 Diesel Generator Control Rooms (695' elevation);
- Fire Area 117–Unit 2 4KV Bus 25 Room (718' elevation); and
- Fire Area 118–Unit 2 4KV Bus 26 Room (718' elevation).

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 implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. 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 five quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On January 20, 2015, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training 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;
- crew's 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 simulator sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On January 26, 2015, the inspectors observed the licensed operators perform activities associated with an unplanned shutdown of Unit 1. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's 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 procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Reactor Controls (Function RE–01); and
- Structures Monitoring.

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

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

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

b. Findings

No findings 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 affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- D2 EDG 24 month planned maintenance overhaul activities;

- 11 and 12 residual heat removal operability impact from gas void formation;
- 12 residual heat removal operability impact from additional gas void formation;
- 22 turbine driven auxiliary feedwater pump inoperability due to valve malfunction; and
- 2RY transformer bus ties breaker failure to close.

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.

Documents reviewed are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- CAP 1461863–Potential air leak inside Unit 1 containment;
- CAP 1463101–Turbine driven auxiliary feedwater pump supply to 22 steam generator operability evaluation;
- CAP 1463696–14 fan coil unit operability evaluation;
- CAP 1464710–12 battery loading capacity factor impact on operability;
- CAP 1465572–Voids discovered in Residual Heat Removal System;
- CAP 1469350–Untimely resolution of equipment qualification issues; and
- CAP 1470353–Auxiliary Building temperatures challenging electrical switchgear temperature limits.

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 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

Introduction: An inspector identified finding of very low safety significance and a NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," occurred on January 27, 2015, due to the failure to follow Procedure FP–OP–OL–01, "Operability/Functionality Determination," while assessing the operability of the 14 CFCU and the Unit 1 containment. Specifically, personnel failed to perform an immediate operability determination for the 14 CFCU and the Unit 1 containment after the inspectors identified that the 14 CFCU was potentially leaking.

Description: On January 27, 2015, the inspectors performed a Unit 1 containment entry to inspect the containment fan coil units and identified a puddle of water near the 14 CFCU. The inspectors reported the puddle of water to the Outage Control Center (OCC) Shift Outage Manager at approximately 11:00 a.m. The licensee initiated CAP 1463696 to document the puddle and notified the control room that the 14 CFCU might be leaking.

Control room personnel dispatched two non-licensed operators to the 14 CFCU. At 12:12 p.m., the non-licensed operators informed the control room that the 14 CFCU was sweating, that the water on the floor appeared to be condensation, and that no active leaks were identified. Based upon the report from the non-licensed operators, the Unit 1 shift supervisor made the following log entry:

> *"Received a report that water was noted on the floor near the 14 containment fan coil unit. Based on local observation by an outplant operator, the water appears to be condensation from 14 CFCU and not a cooling water leak. A sample will be taken by chemistry for further analysis."*

At 12:20 p.m., the Unit 1 shift supervisor contacted the OCC and requested that chemistry obtain a sample of the water near the 14 CFCU. The chemistry technicians were not dispatched to sample the water until 2:44 p.m. The inspectors considered the 2 hour and 24 minute delay to be noteworthy due to the fact that any cooling water (river water) leakage from the 14 CFCU would render the CFCU and the Unit 1 containment inoperable and result in placing Unit 1 in a one hour TS limiting condition for operation.

At 3:45 p.m., the chemistry department completed analyzing a sample of water taken from the puddle near the 14 CFCU. The following log entry was made by the chemistry representative in the OCC:

> *"Sample of water from the bermed area by the 14 CFCU showed a total hardness of 500 parts per million (ppm). Due to interference from the area the sample was collected from, a normal river hardness around 250 ppm, and no observed leaks during inspection, these results appear to be inconclusive.*

Additional analysis is being run to provide additional data for the source of the water."

During operations shift turnover activities at approximately 5:00 p.m., the off-going and on-coming shift managers discussed CAPs that needed to be reviewed. This discussion included the need to review CAP 1463696 and document an immediate operability determination in the operations status notes section of the CAP.

The following day the inspectors reviewed the previous day's control room and OCC log entries. The inspectors noted the log entries indicating that the water near the 14 CFCU "appeared to be condensate" and that the chemistry sample results were "inconclusive." Due to a previous NRC finding and violation documented in NRC IR 05000282/2014003; 05000306/2014003, the inspectors knew that it was extremely difficult to determine operability of a CFCU without a conclusive chemistry sample. In addition, guidance provided in NRC IMC 0326, "Operability Determinations and Functionality Assessments for Conditions Adverse to Quality," stated that an SSC was to be considered inoperable if the results of the operability assessment were indeterminate.

The inspectors considered the words "indeterminate" and "inconclusive" to be synonymous. The inspectors then reviewed the operations status notes section for CAP 1463696 to determine whether operations had provided an updated immediate operability determination within the CAP. The inspectors found that the shift manager had not completed the review discussed as part of the shift turnover meeting at 5:00 p.m. the previous evening. As a result, no immediate operability determination on the 14 CFCU had been made even though approximately 21 hours had elapsed since the puddle on the floor was identified. The inspectors brought this issue to the attention of operations management who agreed with the inspectors' assessment. On January 28, 2015, the shift manager updated the operations status notes for CAP 1463696 to state that the 14 CFCU was operable. However, the status notes were updated after Unit 1 was in Mode 5 and the CFCUs were no longer required to be operable by TS.

<u>Analysis</u>: The inspectors determined that the failure to perform an immediate operability determination on the 14 CFCU, as required by Step 5.3.1 of Procedure FP–OP–OL–01, was a performance deficiency associated with the Barrier Integrity cornerstone. This deficiency was more than minor because if left uncorrected the failure to perform operability determinations as required by procedure could result in incorrect/untimely operability conclusions and the failure to take action to correct degraded or deficient conditions as required by the TS. In addition, this is the second example of an untimely CFCU operability determination identified by the inspectors in the last 10 months.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," Part B, was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Teamwork area because individuals and work groups failed to communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety was maintained (H.4).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstance and be accomplished in accordance with these procedures. The licensee implemented the operability determination process (an activity affecting quality) using Procedure FP–OP–OL–01, “Operability/Functionality Determinations.” Step 5.3.1 of the procedure stated that an immediate determination of operability shall be performed for SSCs that are required to be operable by TS or that perform a required support function for SSCs required to be operable by TS. On January 27, 2015, when the puddle near the 14 CFCU was first identified, Unit 1 was operating in Mode 3; the 14 CFCU and the Unit 1 containment were required to be operable by TS. Contrary to the above, on January 27, 2015, the licensee failed to perform an immediate operability determination for the 14 CFCU after water was identified on the floor as required by Procedure FP–OP–OL–01.

Because this violation was of very low safety significance and was entered into the licensee’s CAP as CAP 1463696, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2015001–01: Failure to Perform Immediate Operability Determination for 14 CFCU as Required by Procedure)**. Corrective actions for this issue included completing the immediate operability determination and revising Procedure C35 AOP4, “Cooling Water Leakage in Containment,” to include information on responding to potential CFCU leakage.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification(s):

- Engineering Change (EC) 24352–D1/D2 Fan Blade Pitch Positioners (Temporary);
- ECs 25282 and 25283–Change Normal Position of 11 and 12 Reactor Coolant Pump #3 Seal Leak Off Vent Valves and Install Vented Caps (Temporary); and
- EC 25262–Accept As-Is Temperature Monitoring Equipment Used to Satisfy NRC Bulletin 88–08 (Permanent).

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system(s). The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two temporary modification samples and one permanent plant modification sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 122 control room chiller damper test following maintenance including solenoid replacement;
- Unit 1 panel 118 voltage regulator input and output testing following fuse replacement;
- Unit 2 instrument air supply to containment valve testing following solenoid replacement;
- Unit 2 pressurizer relief tank testing following rupture disk replacement;
- 12 reactor coolant pump operation following seal replacement; and
- 21 motor driven auxiliary feedwater valve testing following the failure of the cooling water supply valve to operate.

These activities were selected based upon the structure, system, or component's 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 TSs, 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 corrective action documents associated with PM tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities–Unit 1

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled Unit 1 outage that began on January 26, 2015, and continued through February 12, 2015, to replace the #12 RCP seal. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with this outage and a similar outage that occurred in December 2014.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

Introduction: A self-revealing finding of very low safety significance and an NCV of TS 5.4.1 was identified on December 19, 2014, due to the licensee's failure to follow Procedure FP–MA–FME–01, "Foreign Material Exclusion and Control." Specifically, workers failed to implement and adhere to the FME control requirements for a Level 1 foreign material exclusion area (FMEA) when replacing the #12 RCP seal and its associated piping during Refueling Outage 1R29. The failure to implement and adhere to the FME control requirements resulted in introducing foreign material into the #12 RCP seal. This caused RCP seal degradation in December 2014 and January 2015 and led to two subsequent Unit 1 reactor shutdowns.

Description: During Refueling Outage 1R29, which occurred in October and November 2014, the licensee replaced the existing Unit 1 RCP seals with Flowserve N–9000 seals as specified in EC 21790 and WO 500315. This change included modifying the seal leak-off piping, seal housing and coupling. The licensee returned Unit 1 to power operation on November 20, 2014.

On November 28, 2014, operations personnel initiated CAP 1457740 after identifying an increase in the Unit 1 reactor coolant drain tank (RCDT) level rate of change. The rate of change increase was found while performing the daily reactor coolant system (RCS) leakage test required by TS 3.4.14. According to information included on CAP 1457740, the CAP screening team assigned a "D" significance level (the lowest level) to the CAP and closed the CAP to trend. Two days later, operations personnel initiated CAP 1457811 which stated the following:

> *"Reference CAP 1457740 that identified an increasing trend in Unit 1 RCDT level rate of change. Further investigation suggests that the 12 RCP seal #3 may be degrading. A review of the 12 RCP seal P3 cavity pressure shows a steady increasing trend along with a decreasing trend in seal leak-off temperature to the*

volume control tank, suggesting that more flow is being diverted through the #3 seal."

The corrective action screening team requested that the engineering department evaluate the condition of the 12 RCP seal to determine if an adverse condition existed. This condition evaluation was scheduled for completion on December 31, 2014. The screening team also assigned the development and issuance of an operational decision making document. The purpose of this document was to provide a plan to monitor the RCP seal performance and decision points regarding a plant shut down.

On December 7, 2014, operations personnel noticed that the Unit 1 unidentified RCS leakage rate increased during the daily surveillance test. The licensee performed a Unit 1 containment entry and found that the increase in unidentified leakage was due to leakage from the 12 RCP seal. The licensee monitored the RCS unidentified leakage rate and the RCP seal leakage until December 10, 2014, when the Unit 1 RCS unidentified leakage reached 0.85 gallons per minute. At this leakage rate, the licensee shut down the Unit 1 reactor to replace the 12 RCP seal. The inspectors noted that the operational decision making document discussed above was not reviewed and approved until December 10, 2014.

During the outage, the licensee removed the #12 RCP seal and sent it to Flowserve for disassembly and analysis. During the seal disassembly process, Flowserve identified granular metallic foreign material throughout the seal. The report from Flowserve stated the following with regards to the disassembly and analysis of the #12 RCP seal:

> *"This foreign material resulted in gross damage at the sealing surface of the stationary face on all three stages. A critical finding in the forensic analysis was the amount of debris on the pump side of the first stage stationary seal face as well as its size. The amount of debris found prior to the entry into any of the seal stages is a clear indication that the foreign material came from outside of the seal package."*

The licensee also implemented a troubleshooting plan. Activities performed to complete the troubleshooting plan determined that the #12 RCP seal degraded due to upper stage seal degradation caused by foreign material intrusion. The licensee performed some activities to determine the source of the foreign material. Based upon a copy of the troubleshooting plan from December 22, 2014, the licensee initially believed that the foreign material was introduced by activities unrelated to the seal replacement. This conclusion was reached based on the following information in the troubleshooting plan:

- No abnormal items reported in the seal injection filters when removed;
- A WO history review of piping and valves specific to the injection line for the #12 RCP revealed no invasive maintenance activities that could have introduced the foreign material to the system; and
- All work to remove the old seal and install the new seal was performed under the highest level of FME control. No issues were reported by the craft during the disassembly or reassembly that would indicate a piece of stainless steel was left in the pump.

The licensee used the information in the troubleshooting plan to develop a second operational decision making document. This operational decision making document was

reviewed by the Plant Operating Review Committee on December 22, 2014. The inspectors reviewed the operational decision making document and noted the following problem statement:

> *"Foreign material is the known primary cause for the failure of the operating 12 RCP seal shortly following installation in 1R29. Some foreign material has been removed from the top face of the pump radial bearing. This may or may not be all the material in the credible regions of the pump that could reasonably generate the material known to have intruded into the seal to cause the failure. If all the source material has not been removed, the seal may be in danger of another similar failure."*

The licensee considered several options to address the fact that foreign material could still be present within the #12 RCP. After reviewing the potential risk and consequences of each option, the licensee decided to accept the condition of the #12 RCP as-is. This was based upon the fact that the licensee established criteria to monitor the #12 RCP seal performance and to shut down the plant prior to any RCP seal leakage reaching the RCS unidentified leakage limit in TS 3.4.14. The licensee also continued their efforts to determine the source of the foreign material.

In January 2015, the licensee discovered pictures from the November 2014 refueling outage which were taken in the #12 RCP seal area. These pictures showed poor foreign material exclusion practices were present in the area. The licensee also found that foreign material exclusion controls specified in Procedure FP–MA–FME–01 and EC 21790 (which was used to describe the RCP seal changes and how the seals should be replaced) were not properly implemented. Specifically, Section 8.1.5 of the EC stated that the interior surfaces of piping shall be appropriately cleaned after fabrication to remove foreign materials and place the piping system into an appropriate condition for operation. This information was not translated into WO 500315. The inspectors reviewed Procedure FP–MA–FME–01, "Foreign Material Exclusion and Control." Section 5.1.1 stated that a Level 1 FMEA (highest level) was required to be established when a loss of FME integrity could result in personnel injury, nuclear fuel failure, reduced safety system or station availability, or an outage extension or significant cost for recovery. In addition, Step 5.1.1.4 stated that a Level 1 FMEA was required when performing intrusive work on SSCs that provide a direct path to the reactor vessel such as the RCS at Prairie Island. Lastly, Section 5.2 of FP–MA–FME–01 stated that a formal FME control plan was required for large projects with FME Level 1 activities. The inspectors determined that a Level 1 FMEA had been established during the RCP seal modification, but the area was improperly controlled. Specifically, the appropriate tooling was not used to minimize the generation and migration of foreign material into the RCP seals and piping. In addition, a formal FME control plan was not established for the RCP seal replacement modification even though this was considered a large project. According to the licensee's root cause evaluation for this issue, many of the activities discussed above were to be completed by contractors and supplemental personnel. Since many of these activities were not performed, the licensee determined that the failure to follow the foreign material exclusion procedure requirements was due to their improper control of contractors and supplemental personnel.

On January 8, 2015, the licensee documented CAP 1461540 regarding the declining performance of the #12 RCP seal. The inspectors reviewed #12 RCP pump information located on the plant process computer and verified that the #12 RCP seal differential

pressures began degrading on approximately December 30, 2014. Based upon information in the control room logs, operations personnel began documenting a review of the #12 RCP seal differential pressures on January 9, 2015. On January 24, 2015, operations personnel identified an increase in the Unit 1 RCS unidentified leakage during the daily surveillance test. Two days later plant personnel entered the Unit 1 containment to inspect the #12 RCP and identified external shaft seal leakage coming from the pump seal. Based upon this information, operations personnel took action to shut down the Unit 1 reactor so that the #12 RCP seal piping could be flushed of foreign material and the pump seal could be replaced.

Analysis: The inspectors determined that the failure to follow the foreign material exclusion procedure was a self-revealing performance deficiency that required evaluation using the Significance Determination Process (SDP). During the inspection period, the licensee expressed concerns regarding the inspectors' decision to classify this performance deficiency as self-revealing rather than licensee identified. Inspection Manual Chapter 0612, "Power Reactor Inspection Reports," defines a licensee identified finding as follows:

> *"a finding that is neither NRC identified or self-revealed. Most, but not all, licensee identified findings or violations are discovered through a licensee program or process. Examples of licensee programs that may result in such findings or violations are post maintenance testing, surveillance testing, drills, critiques or audits conducted by or for the licensee. Other examples of licensee identified findings or violations are those that are identified by the licensee as a result of their deliberate and focused observation during the course of performing their normal duties."*

Conversely, IMC 0612 defines a self-revealing finding as follows:

> *"a finding or violation developed from issues that become self-evident and require no active and deliberate observation by the licensee or NRC inspectors to determine whether a change in process or equipment capability or function has occurred. Self-revealing findings and violations become readily apparent to either NRC or licensee personnel through a readily detectable degradation in the material condition, capability or functionality of equipment or plant operations and requires minimal analysis to detect."*

The inspectors determined that the licensee first noticed a potential issue with the #12 RCP seal when they identified that the RCDT level rate of change was increasing on November 28, 2014. This rate of change increase was identified as part of the daily RCS leakage surveillance testing required by TS 3.4.14. As provided in IMC 0612, the NRC may classify findings or violations as licensee identified if an issue was identified as a result of performing surveillance testing. However, the purpose of the surveillance test has to be directly related to the identified finding or violation to demonstrate that the finding or violation was identified as a result of deliberate and focused observation.

The inspectors reviewed the TS Bases for TS 3.4.14 and TS Surveillance Requirement 3.4.14.1. The inspectors found that the purpose of the daily RCS leakage surveillance test was to ensure that the integrity of the reactor coolant system pressure boundary was maintained. In addition, the inspectors noted that the TS Bases specifically stated that leakage past seals and gaskets was not RCS pressure boundary

leakage. Based upon this information, the inspectors concluded that the purpose of the RCS leakage surveillance test was not directly related to identifying RCP seal degradation or potential findings or violations due to poor foreign material exclusion control. The inspectors also concluded that the initiation of CAP1461540 on January 8, 2015, failed to satisfy the criteria to classify the second seal degradation as licensee identified since information contained in the licensee's December 22, 2014 operational decision making document acknowledged that foreign material remained in the #12 RCP and that subsequent seal degradation could occur.

The inspectors determined that the failure to follow the FME procedure was more than minor because it was associated with the equipment performance attribute of the Initiating Events cornerstone and impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined that this issue was of very low safety significance (Green) because each question provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," was answered "No." The inspectors concluded that this finding was cross-cutting in the Human Performance, Work Management area because the organization failed to implement a process of planning, controlling, and executing work activities such that nuclear safety was the overriding priority. In addition, the work process failed to include the identification and management of risk commensurate to the work and the need for coordination with different groups or job activities (H.5).

Enforcement: TS 5.4.1 states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Section 9 of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires procedures for performing maintenance. Specifically, Regulatory Guide 1.33, 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. Procedure FP-MA-FME-01, "Foreign Material Exclusion and Control," was the procedure used by the licensee to ensure that foreign material was not introduced into safety-related systems or components during the performance of maintenance on equipment.

Section 5.1.1 of Procedure FP-MA-FME-01 stated that a Level 1 FMEA (highest level) was required to be established when a loss of FME integrity could result in personnel injury, nuclear fuel failure, reduced safety system or station availability, or an outage extension or significant cost for recovery. Step 5.1.1.4 stated that a Level 1 FMEA was required when performing intrusive work on SSCs that provide a direct path to the reactor vessel such as the RCS at Prairie Island. Lastly, Section 5.2 stated that a formal FME control plan was required for large projects with FME Level 1 activities.

Contrary to the above, between October 7 and December 19, 2014, the licensee failed to properly establish a Level 1 FMEA during RCP seal replacement activities even though the RCP seal replacement work was performed on portions of the RCS that provided a direct path to the reactor vessel and a loss of FME integrity could have resulted in nuclear fuel failure, reduced safety system or station availability, or an outage extension or significant cost for recovery. In addition, a formal FME control plan was not developed even though the RCP seal replacement activity determined to be a large

project with FME Level 1 activities. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1459098, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015001–02: Failure to Follow Foreign Material Exclusion Procedure during Reactor Coolant Pump Seal Replacement)**. Corrective actions for this issue included replacing the RCP seal, flushing the seal piping and establishing a process to review work document quality to ensure that appropriate programmatic requirements were included.

.2 Other Outage Activities–Unit 2

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled Unit 2 outage that began on March 5, 2015, and continued through March 25, 2015, to repair the pressurizer relief tank rupture disk, replace several American Switch Company (ASCO) solenoid valves and address leakage on the containment fan coil units. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings 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:

- Surveillance Procedure (SP) 1001AA–Daily Reactor Coolant System Leakage Test (RCS leak detection);
- SP 1052–Auxiliary Spray Line Temperature Monitoring Test (Routine);
- SP 1093–D1 Diesel Generator Monthly (Routine);
- SP 1094–Bus 15 Load Sequencer Test (Routine);

- SP 1159–Train B Cooling Water Valves Quarterly Test (IST);
- SP 1406–Main Steam Isolation Valve Inservice Test (Isolation valve);
- SP 2130B–Train B Containment Vacuum Breaker Quarterly Test (Isolation valve); and
- Test Procedure (TP) 1468 Unit 1 Generic Letter 08–01 RHR train A & B gas void inspects (Routine);

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; 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; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable 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;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all 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, one reactor coolant system leak detection inspection sample, and two containment isolation valve samples as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on January 20, 2015, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the corrective action program. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator (PI) for Units 1 and 2 for the period from the first quarter of 2014 through the fourth quarter of 2014. 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 7, dated August 31, 2013, was used. The inspectors reviewed the licensee's operator narrative logs, CAPs, event reports and NRC Integrated IRs for the period provided above 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 unplanned scrams per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes per 7000 Critical Hours performance indicator for Units 1 and 2 for the period from the first quarter of 2014 through the fourth quarter of 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 31, 2013, was used. The inspectors reviewed the licensee’s operator narrative logs, CAPs, maintenance rule records, event reports and NRC Integrated IRs for the period provided above 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 unplanned power changes per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator for Units 1 and 2 for the period from the first quarter of 2014 through the fourth quarter of 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 31, 2013, and NUREG–1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, was used. The inspectors reviewed the licensee’s operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, CAPs, event reports and NRC Integrated IRs for the period provided above 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 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 Security

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

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify 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: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; 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 to this report.

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 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 condition report packages.

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

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Review of the Unit 1 Auxiliary Spray Line Temperature Monitoring Program as Specified in NRC Bulletin 88–08

a. Inspection Scope

During the Unit 1 forced outage, the inspectors performed an initial tour of the containment building on January 27. While performing their tour, the inspectors noted a temporary power supply receptacle, temperature monitoring panel and associated cabling permanently mounted on a wall located on the 695' elevation in containment. The inspectors communicated the configuration to the Licensee and CAP 1463696, "NRC Observation Report from U1 Containment Walk Through," was generated and a condition evaluation was performed. Additional discussions with licensing, operations and engineering personal revealed that the associated equipment was intended to monitor temperature on the pressurizer auxiliary spray line to detect temperature gradients that could induce thermal stress and result in crack formation and subsequent unisolable RCS leak. The licensee established procedure SP 1052, "Auxiliary Spray Line Temperature Monitoring," to periodically monitor temperatures across the auxiliary spray line to detect the existence of thermal stress to prevent crack formation and propagation. Additional review by the inspectors revealed that NRC Bulletin 88–08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," and subsequent NRC supplemental letters stated in part, that the Licensee must ensure that the piping will not be subjected to unacceptable thermal stresses. Based on this information, the inspector performed an independent review of the corrective action program and identified that the site had not completed SP 1052 numerous times between 2011 and December 2014. However, because the Licensee had successfully completed SP 1052 in December 2014 ensuring that thermal gradients and resultant thermal stresses did not exist, the inspectors determined that the Licensee had satisfactorily demonstrated compliance with NRC Bulletin 88–08.

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

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: Review of Licensee Corrective Actions to Address Maintenance Rule Notice of Violation

a. Inspection Scope

In July 2013, the inspectors documented a Notice of Violation (NOV) in NRC IR 05000282/2013003; 05000306/2013003; due to the licensee's failure to monitor SSCs as required by 10 CFR 50.65 (commonly known as the Maintenance Rule). The licensee responded to the violation by letter dated August 28, 2013, and as supplemented on November 22, 2013. The inspectors reviewed the reason for the violation and the corrective actions taken to address the maintenance rule deficiencies. The inspectors monitored the licensee's maintenance rule re-scoping progress by

attending scoping meetings and reviewing the revised scoping documents. The inspectors reviewed the licensee's daily corrective action program report to verify that maintenance rule items were being identified at a low threshold and corrected commensurate with their significance. The inspectors also reviewed systems designated as maintenance rule (a)(1) SSCs during their quarterly maintenance rule inspections to verify that maintenance rule action plans were developed as required.

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

b. Findings

No findings were identified.

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

.1 Unit 2 Shutdown Due to Loss of Instrument Air to Containment Building

a. Inspection Scope

On March 5, 2015 at 1:38 a.m., Unit 2 experienced a loss of instrument air to containment when the reactor building instrument air isolation control valve (CV–31742) unexpectedly failed closed. The inspectors responded to the control room and monitored the operator actions taken to address the event. The inspectors also reviewed the procedures used during this event to determine whether the control room operators responded properly. 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

Introduction: A self-revealing finding of very low safety-significance (Green) and an NCV of 10 CFR 50.49 was identified on March 5, 2015, for the failure to keep EQ files current and the failure to replace or refurbish EQ electrical equipment at the end of its designated life. Specifically, the licensee had identified numerous EQ file errors in May 2014. These file errors resulted in the EQ designated life for multiple safety-related solenoid valves being non-conservative. Correction of the file errors should have resulted in the replacement of ten solenoid valves on a near-term basis. However, none of the solenoid valves has been replaced prior to the event on March 5, 2015.

Description: As discussed above, the inspectors responded to the control room after being notified of the loss of air event. The inspectors noted that per design, a loss of instrument air to containment caused all air supplied safety-related valves to position to a fail-safe positon. This resulted in a loss of letdown capability which required operators to reduce charging flow to the RCS. With letdown unavailable, water supplied to RCS was removed through the reactor vessel head vent to the pressurizer relief tank (PRT). Subsequent water flow to the PRT exceeded the capacity of the PRT causing a relief disk rupture when pressure reached 100 psi. The PRT is not equipped with a relief valve, instead, a rupture disk is used to prevent over pressurization of the tank. The rupture of the disk released steam that triggered a fire alarm in containment. Because Licensee personnel could not enter containment to physically verify there was no fire

within the required time limit of 15 minutes, the shift manager declared a Notice of Unusual Event (NOUE) at 4:06 a.m. Operations personnel also took action to remove the unit from service. The licensee also determined that CV–31742 had failed closed due to the failure of its solenoid valve (SV–33283).

After achieving mode 3, operations and maintenance personnel took action to replace the failed solenoid valve, restore instrument air to containment and sample the air in containment. The Licensee subsequently determined it was safe for plant personnel to enter the containment building. Once inside containment, Licensee personnel were visually able to confirm there was no sign of a previous or active fire in containment. Upon verification that a fire had not occurred in the Unit 2 containment building, the Licensee terminated the NOUE at 12:18 a.m. on March 6, 2015. The inspectors verified that all actions described above were performed in accordance with the associated procedures in a timely and effective manner.

Following the event, the inspectors reviewed the licensee's CAP database to determine whether any previous issues had been identified regarding solenoid valves or SV–33283. The inspectors also monitored the licensee's actions to determine the cause of the solenoid valve's failure. Based upon information contained in a solenoid valve failure analysis report dated March 27, 2015, the solenoid valve failed due to manufacturing defect internal to the valve's coil. Since this defect was unable to be detected by the licensee during routine operation and testing, this was not considered to be a performance deficiency that was within the licensee's ability to foresee and correct.

During the inspectors' review of the corrective action program database, the inspectors identified CAP 1431268 which was written on May 19, 2014. This CAP documented multiple deficiencies found during a review of the EQ program. The CAP contained the following information:

> *"The qualification calculations of ASCO solenoid valves contained several errors. For a specific model number, the incorrect test report was applied. Also, a non-conservative value for the temperature rise was used, resulting in a longer life than actually exists. This will require near-term replacement of approximately 10 valves ahead of schedule."*

The inspectors discussed the information provided above with engineering personnel to determine if SV–33283 was one of the ten specific ASCO solenoid valves referred to in CAP 1431268. Engineering personnel informed the inspectors that SV–33283 was one of the ten valves needing replacement. The inspectors were also informed that due to the deficiencies identified in CAP 1431268 the EQ designated life was reduced from 17.3 years to 4.96 years. The inspectors performed an additional review of CAP 1431268 and held discussions with engineering and work management personnel to determine what actions had been taken to correct the EQ files and replace the ten valves referred to in the CAP. The inspectors found that little to no action had been taken to correct either condition. Specifically, a work order was written to replace a different solenoid valve during the fall 2014 Unit 1 refueling outage; the inspectors found that this valve replacement had not occurred. In addition, no other work orders had been written for the remaining nine valves until March 6, 2015, due to the licensee's belief that the issues identified in CAP 1431268 were programmatic in nature and had no impact on plant equipment. The licensee replaced eight of the nine valves during the outage that followed the loss of air event. These valves had been installed for at least

13 years. The remaining valves were scheduled for replacement in April 2015. The inspectors also found that the licensee had assigned an action to initiate a process to reconstitute the EQ files and other EQ program documentation. Although this action was originally scheduled for completion on June 23, 2014, it had been extended twice and was not yet complete. The failure to replace or refurbish the solenoid valves at the end of their designated life and to correct the EQ file deficiencies violated the requirements of 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

Analysis: The inspectors determined that the failure to keep the information in the EQ files current and the failure to replace or refurbish EQ equipment at the end of its designated life was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because if left uncorrected the failure to maintain the EQ files and to replace or refurbish EQ equipment could result in a more significant safety concern. Specifically, the inaccurate files could result in EQ equipment not being refurbished or replaced as required. In addition, the failure to replace or refurbish EQ equipment installed beyond its designated life could result in equipment failure during normal operation or post-accident conditions.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and determined this issue was of very low safety significance because each of the questions provided in IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," was answered "No." The inspectors concluded that this issue was cross-cutting in the Problem Identification and Resolution, Evaluation area because the licensee had not thoroughly evaluated CAP 1431268 to ensure that the resolution addressed the causes and extent of condition commensurate with the safety significance (P.2).

Enforcement: Title 10 CFR Part 50.49, states, in part, the licensee shall keep the list of environmentally qualified equipment and information within the file current and retain the file in auditable form for the entire period during which the covered item is installed in the nuclear power plant or stored for future use. In addition, 10 CFR 50.49(e)(5) states that environmentally qualified electrical equipment must be replaced or refurbished at the end of its designated life unless ongoing qualification demonstrates that the item has additional life.

Contrary to the above, on March 5, 2015, the licensee had not kept the information in EQ file PI–19.1A.001, "ASCO Solenoid EQ File," current. In May 2014, the licensee identified that the EQ file had incorrectly determined the designated life of specific ASCO solenoid valves to be 17 years based upon the application of an incorrect test report and temperature rise data. When the correct data was used the designated life was determined to be 4.96 years. Once the revised designed life was known, no action was taken to replace or refurbish the specific ASCO solenoid valves or justify the valves had additional life through the performance of ongoing qualification activities. Because this violation was of very low safety significance and was entered into the CAP as CAPs 1469350 and 1470457, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015001–03; 05000306/2015001–03: Untimely Resolution of Environmental Qualification Issues)**. Corrective actions for this issue included replacing the ASCO solenoids installed beyond their designated life and assigning a corrective action to track the initiation, funding and execution of an EQ file reconstitution project.

4OA5 Other Activities

.1 (Closed) Notice of Violation 05000282/2013003–02; 05000306/2013003–02: Failure to Monitor Structures, Systems and Components as Required by 10 CFR 50.65

a. Inspection Scope

As discussed in Section 4OA2.4 of this inspection report, the inspectors reviewed the licensee's corrective actions taken to address Notice of Violation 05000282/2013003–02; 05000306/2013003–02. The licensee responded to the violation by letter dated August 28, 2013, and as supplemented on November 22, 2013. The inspectors reviewed the reason for the violation and the corrective actions taken to address the maintenance rule deficiencies. The inspectors monitored the licensee's maintenance rule re-scoping progress by attending scoping meetings and reviewing the revised scoping documents. The inspectors reviewed the licensee's daily corrective action program report to verify that maintenance rule items were being identified at a low threshold and corrected commensurate with their significance. The inspectors also reviewed systems designated as maintenance rule (a)(1) SSCs during their quarterly maintenance rule inspections to verify that maintenance rule action plans were developed as required. This item is closed.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 9, 2015, the inspectors presented the inspection results to Mr. K. Davison, Site Vice President, 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee</u>

K. Davison, Site Vice President
S. Sharp, Director Site Operations
E. Blondin, Engineering Director
C. Younie, Plant Manager
T. Allen, Assistant Plant Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
H. Butterworth, Nuclear Oversight Manager
F. Calia, Business Support Manager
B. Carberry, Emergency Preparedness Manager
C. Childress, Maintenance Manager
J. Corwin, Security Manager
D. Gauger, Chemistry/Environmental Manager
G. Johnson, Senior Manager Site Engineering
S. Martin, Performance Assessment Manager
B. Meek, Safety and Human Performance Manager
J. Ruttar, Operations Manager
D. Vincent, Acting Regulatory Affairs Manager

<u>Nuclear Regulatory Commission</u>

K. Riemer, Chief, Reactor Projects Branch 2
T. Beltz, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000306/2015001–01	NCV	Failure to Perform Immediate Operability Determination for 14 CFCU as Required by Procedure (Section 1R15.1)
05000282/2015001–02	NCV	Failure to Follow Foreign Material Exclusion Procedure during Reactor Coolant Pump Seal Replacement (Section 1R20.1)
05000282/2015001–03; 05000306/2015001–03:	NCV	Untimely Resolution of Environmental Qualification Issues (Section 4OA3.1)

Closed

05000306/2015001–01	NCV	Failure to Perform Immediate Operability Determination for 14 CFCU as Required by Procedure (Section 1R15.1)
05000282/2015001–02	NCV	Failure to Follow Foreign Material Exclusion Procedure during Reactor Coolant Pump Seal Replacement (Section 1R20.1)
05000282/2015001–03; 05000306/2015001–03:	NCV	Untimely Resolution of Environmental Qualification Issues (Section 4OA3.1)
05000282/2013003–02; 05000306/2013003–02	NOV	Failure to Monitor Structures, Systems and Components as Required by 10 CFR 50.65 (Section 4OA5.1)

LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment

- 1C19.2; Containment System Ventilation Unit 1; Revision 27
- 2C20.7.AOP1; Failure of D5 or D6 Keep Warm System; Revision 7
- 2C20.7; D5/D6 Diesel Generators; Revision 40
- C18.1; Engineered Safeguards Equipment Support Systems; Revision 38
- C19.2-8; Containment Vessel Air Handling System Unit 1; Revision 15
- C37.14; Service Building Ventilation System; Revision 13
- C37.9; Control; Relay, and Computer Room Ventilation; Revision 28
- CAP 1459692; 121/122 CR Humidifier 50.59 Screening; March 5, 2015
- CAP 1462019; 12 Reactor Vessel Gap Cooling Fan Tripped Unexpectedly; January 13, 2015
- CAP 1462389; Replacing MOLRs and the Wiring in Breaker 122E-56; January 15, 2015
- CAP 1462631; Unable to Transfer to Standby L/O Filters on both D6 Engines; January 18, 2015
- CAP 1467882; NRC Questioned Scaffold Configuration in CR Chiller Room; February 26, 2015
- CAP 1469341; Low Humidity Effects on Steam Exclusion Instrumentation; March 9, 2015
- D80; Scaffolds; Ladders and Cable Tray Platforms; Revision 29
- ICPM 1-466; Reactor Vessel Gap and Support Cooling Fans Flow Instruments Calibration; Revision 5
- SP 1290; Steam Exclusion System Instrument Check – Weekly; Revision 22

1R05 Fire Protection

- CAP 1461070; SP 2106 Completed Unsat; January 5, 2015
- CAP 1461737; Surveillance WO Completed Incorrectly; January 9, 2015
- CAP 1461762; SP 2107B Periodicity Questioned by the NRC; January 9, 2015
- CAP 1461782; SP 2106 Fire Panel 70466 Detector Sensitivity Check Late; January 10, 2015
- CAP 1462072; Fire Detection Surveillance Requirements Removed from F5 App K; January 13, 2015
- F5 Appendix A; Fire Strategies; Revision 30
- F5 Appendix F; Fire Hazard Analysis; Revision 29
- F5 Appendix K; Fire Protection Systems Functional Requirements; Revision 20
- SP 2106; Fire Panel 70466 Detector Sensitivity Check; Revision 11
- SP 2107B; D5/D6 Fire Protection Test on Non-Trip Devices; Revision 6

1R11 Licensed Operator Requalification

- Simulator Exercise Guide P9114SE-0601; Cycle 14F As-Found Evaluation; Revision 0

1R12 Maintenance Effectiveness

- (a)(1) Action Plan 1420712-01; April 1, 2014

- BM-01; Provide Plant Structures Support Equipment in the Scope of the Maintenance Rule; January 29, 2015
- BM-02; Provide Passive Barriers and Openings for Critical Drainage Paths used to Direct Internal Flooding Water Away From Key Plant Equipment; January 29, 2015
- BM-03; Provide Critical Floor Drains for Drainage Paths; January 29, 2015
- CAP 1420712; Reactor Controls Reliability of Input/Output Components; February 28, 2014
- CAP 1426609; Maintenance Rule (a)(3) Report; No Date Provided
- CAP 1427220; 12 Steam Generator Power Operated Relief Valve not Fully Closed; November 22, 2014
- CAP 1433726; Structures Monitoring Reports not Complete During 2014 License Renewal;
- CAP 1438730; Equipment Causal Evaluation 1352114-05 Actions Result in Unnecessary Maintenance; July 17, 2014
- CAP 1458004; Maintenance Rule Condition Monitoring Events Exceeded Criteria; December 2, 2014
- CAP 1458004; Plan Goals Exceeded; December 2, 2014
- Causal Evaluation 1352114-05; 12 Steam Generator Steam Flow Blue Channel Failed High; October 28, 2014
- FP-E-MR-01; Maintenance Rule Process; Revision 5
- H24.3; Structures Monitoring Program; Revision 11
- Maintenance Rule Functional Failure Evaluation 1352114-02; 1FI-474 Blue Channel High-High Steam Flow Failed High; September 19, 2012
- MRA 1458004-01; (a)(1) Action Plan for Function RE-01; Revision 3
- PM 3586-10; Periodic Structures Inspection; Revision 6
- QF0584; (a)(1) Action Plan Development and Action Plan (Monitoring) Goal Setting Template; Revision 2
- SP 1293; Inspection of Flood Control Measures; Revision 26

<u>1R13 Maintenance Risk</u>

- CAP 1466679; Breaker 2RYBT did not Close as Expected in 2C20.5; February 18, 2015
- High Level Work Schedule; Various Weeks
- Work Week Safety Profiles; Various Weeks

<u>1R15 Operability Evaluations</u>

- 2C28.1; Auxiliary Feedwater System Unit 2; Revision 27
- CAP 1270104; Prompt Operability Recommendation for 12 Battery; Revision 7
- CAP 1402805; IEE 2006-062 Does Not Follow Process; October 24, 2013
- CAP 1452674; Revised OPRs Connections to Past Operability & Reportability; October 23, 2014
- CAP 1463101; MV 32247 has Dual Light Indication; January 21, 2015
- CAP 1463696; NRC Observation Report from Unit1 Containment Walk Down; January 28, 2015
- CAP 1463896; Water Found by 14 Containment Fan Coil Unit; January 27, 2015
- CAP 1464710; 12 Battery Margin Issue Related to IEE With Increase Load; February 3, 2015
- CAP 1465110; 11 Battery Requires a Capacity Factor Above 80 Percent; February 6, 2015
- CAP 1470143; High Ambient Temperature in the Auxiliary Building Needs to be Addressed; March 15, 2015
- CAP 1470353; Auxiliary Building temperatures challenging bus temperature limits; March 17, 2015

- EC 25251; Evaluation of Additional Solenoid Valves on SR 125VDC Batteries; February 4, 2015
- Procedure C18.1; Engineered Safeguards Equipment Support System; Revision 39
- Procedure FP-OP-OL-01; "Operability/Functionality Determination; Revision 13
- SP 2102; 22 Turbine-Driven AFW Pump Monthly Test; Revision 97
- TP 1468; Unit 1 Generic Letter 08-01 Inspections; Revision 6

1R18 Plant Modifications

- 50.59 Screening 4763; D1/D2 Room Exhaust and Supply Fan Blade Pitch Positioners; June 3, 2014
- 50.59 Screening 4776; D1 Room Exhaust Fan Blade Positioner Mechanical Bypass; June 14, 2014
- 50.59 Screening 4811; D1/D2 Fan Blade Pitch Positioner Temporary Modification; November 21, 2014
- 50.59 Screening 4949; Open VC-16-4 and VC-16-5 and Add Vented Caps; February 11, 2015
- CAP 1327157; Potential Non-Conservative Heat Up Analysis for D1 and D2 Rooms; February 9, 2012
- CAP 1428983; D1/D2 Components Missed in OPR 1327157; April 30, 2014
- CAP 1433260; Issue with D1/D2 Room Vent Fan Blade Pitch Positioners; June 3, 2014
- EC 25262; 50.59 Screening for Temperature Monitoring on Unit 1 and Unit 2 Auxiliary Spray Lines to Satisfy NRC Bulletin 88-08; Revision 2
- NEI Document 96-07; Guidelines for 10 CFR 50.59 Implementation; Revision 1
- Procedure 1C20.7; D1/D2 Diesel Generators; Revision 44
- Procedure 1C37.10; D1/D2 Diesel Generator Room Cooling System; Revision 17
- WO 503167; Install Bypass on the 121 and 122 Exhaust and Supply Fans; June 3, 2014

1R19 Post Maintenance Testing

- CAP 1467858; Scaffolding for WO#488176 Requested; February 26, 2015
- CAP 1467882; NRC Question: Scaffold Configuration in CR Chiller Room; February 26, 2015
- CAP 1468169; 122 Control Room Chiller Tripped; February 28, 2015
- CAP 1468715; 21 PRT Rupture Disk Has Ruptured; March 5, 2015
- CAP 1469167; Evaluate Effects on U-2 PRT Common Discharge Header Per H42; March 7, 2015
- CAP 1470159; Cooling Water to 21 Motor Driven Feedwater Pump Suction Failed to Close; March 15, 2015
- CAP 1470770; Steps in Work Instructions for WO 519080-01 not Properly N/A'd; March 19, 2015
- Procedure 2C28.1; Auxiliary Feedwater System – Unit 2; Revision 27
- SP 1112; Steam Exclusion Monthly Damper Test; February 26, 2015
- SP 1113; Steam Exclusion Annual Damper Inspection; February 26, 2015
- SP 2193; Cycling Auxiliary Feedwater and Cooling Water Motor Valves; Revision 40
- WO 488176-04; Inspect CD-34145 for Excessive Leakage Past Blades; February 26, 2015
- WO 518387-03; CV-31742, 2 Reactor Bldg Instrument Air Isolation Control Valve PMT; March 5, 2015
- WO 518388-04; 21 PRT Rupture Disk PMT; March 11, 2015
- WO 518401-04; DIST PNL 118 Volt Regulator PMT; March 6, 2015
- WO 519080; 21 Motor Driven Auxiliary Feedwater Pump Suction Valve Failed to Close; March 16, 2015

1R20 Refueling and Outages

- 1C1.3-M2; Unit 1 Shutdown to Mode 2; January 26, 2015
- 1C1.4; Unit 1 Power Operation, Revision; January 26, 2015
- 2C1.2-M2; Unit 2 Startup to Mode 2; Revision 2
- CAP 1469157; WO 518387 Post-maintenance Test was Inadequate for CV-31742 Solenoid Repair; March 7, 2015
- CAP 1469164; Leak Identified on 21 Fan Coil Unit During Walkdown; March 7, 2015
- CAP 1469193; Cooldown Delayed due to LTOP Pressure Regulator not in band; March 8, 2015
- CAP 1469360; NRC Question on Amount of Water Issued From PRT onto Floor of Containment; March 9, 2015
- CAP 1469518; Air Leak on CV-31743; March 10, 2015
- CAP 1469757; Bus 21 Voltage is Greater Than 4400 Volts; March 17, 2015
- CAP 1470159; MV-32026, CLG WTR to 21 MD AFWP SUCT Failed to Close; March 15, 2015
- CAP 1470173; Change in Rate of Level Increase for Unit 1 RCDT; March 15, 2015
- CAP 1471223; Startup PORC Follow-up Recommendation on Equipment Qualification Program; March 23, 2015
- CAP 1471229; No Response from 2N32 Instrument during Reactor Startup; March 23, 2015
- RCE 1459098; 12 Reactor Coolant Pump Seal Root Cause Evaluation Report; February 1, 2015
- SP 2332; Safeguards Buses Weekly Inspection – Operating; March 17, 2015
- WO 518736-02; CV-31743 Air Supply Line PMT; March 11, 2015

1R22 Surveillance Testing

- B27; Main and Auxiliary Steam System; Revision 8
- CAP 1463716; Temperature Monitoring Equipment Not Fully Evaluated as Modification; January 27, 2015
- CAP 1467331; 12 RCP #3 Seal D/P Decreasing; February 23, 2015
- CAP 1467575; NRC ID an Increase in Unit 1 RCS Leakage Before Site; February 24, 2015
- CAP 1467761; Negative Trends in 12 RCP Seal Parameters; February 26, 2015
- CAP 1469923; SV-33133 Stroke Time Outside Reference Range for SP 1151A; March 12, 2015
- Reactor BLDG. Piping, RHR, SI & RS - LINES 10, 100, 102 Isometric Drawing; Revision 76
- SP 1001AA; Daily Reactor Coolant System Leakage Test; Revision 58
- SP 1052; Auxiliary Spray Line Temperature Monitoring; Revision 8
- SP 1070; Reactor Coolant System Integrity Test; Revision 47
- SP 1094; Bus 15 Load Sequencer Test; Revision 34
- SP 1159B; Train B Cooling Water Valve Quarterly Test; Revision 12
- SP 1406; Main Steam Isolation Valve Inservice Test (Cold Shutdown); January 27, 2015
- SP 2297B; Train B Quarterly Cycling of CRDM Cooling Valves; Revision 10
- TP 1468; Unit 1 GL-08-01 Inspections; Revision 6
- WO 515727-01; OPS: Investigate Possible Leakage Through MV-32038; January 14, 2015

4OA1 Performance Indicator Verification

- Control Room Narrative Logs; Various Dates
- Licensee Event Reports; January 1, 2014 through December 31, 2014

4OA2 Identification and Resolution of Problems

- CAP 1291808; SP 1052 Aux Spray Line Temp Monitoring Completed Unsat; June 23, 2011
- CAP 1305783; Unit 1 Auxiliary Spray Line Temp Monitor Configuration Control; December 9, 2011
- CAP 1355608; SP 1052 Aux Spray Line Temp Monitoring Completed Unsat; October 18, 2012
- CAP 1383200; SP 1052 Aux Spray Line Temp Monitoring Completed Unsat; May 13, 2013
- CAP 1385360; SP 1052 Aux Spray Line Temp Monitoring Completed Unsat; June 4, 2013
- CAP 1396124; U1 Data Taker Needs to be Replaced; May 9, 2013
- CAP 1462451; Bulletin 88-08 Temperature Monitors – Plant Impacts; January 30, 2015
- CAP 1463716; Auxiliary Spray Line Temp Monitor Configuration Control; February 6, 2015
- CAP 1464096; NRC Bulletin 88-08 Condition Evaluation; January 30, 2015
- NRC Integrated Inspection Report 05000282/2013003; 05000306/2013003
- Letter from J. Lynch, Site Vice President Prairie Island to NRC Document Control Desk; Reply to a Notice of Violation; August 28, 2013
- Letter from K. Davison, Site Vice President to NRC Document Control Desk; Revised Reply to Notice of Violation; November 22, 2013

4OA3 Event Followup

- 2R28 Outage Scope Change Request #293; PM 31742-2 Unit 2 Reactor Building Instrument Air Isolation AOV Overhaul not Needed; October 11, 2013
- 2R28 Outage Scope Change Request #79; PM 31742-2 Unit 2 Reactor Building Instrument Air Isolation AOV Overhaul; June 7, 2013
- CAP 1431268; EQ Deep Dive: Deficiencies Identified in EQ Program; May 19, 2014
- CAP 1468714; CV-31742 Failed Closed; March 5, 2015
- CAP 1468847; Unplanned Tech Spec Entries; March 5, 2015
- CAP 1468899; Legacy Issue: Potential Non-Conservative EQ Solenoid Valve Qualified Life; March 6, 2015
- CAP 1469107; ASCO Solenoid EQ Qualified Life Non-Conservative in EQ File; March 6, 2015
- CAP 1469135; Program Health Review Identifies Gaps in EQ Program Health Report; March 6, 2015
- CAP 1469136; EQ Solenoid Valves as-found Wiring Doesn’t Match H8-E.1.5.DG; March 10, 2015
- CAP 1469163; ASCO Solenoid EQ Qualified Life Non-Conservative in EQ File; March 7, 2015
- CAP 1469190; Extent of Condition for Non-Conservatism found in EQ File PI-19.1A.001; March 7, 2015
- CAP 1469350; Untimely Resolution of EQ Program Issues Identified in Deep Dive Report; March 9, 2015
- CAP 1470053; EQ File PI-13-4B.001 has a Deficiency; March 16, 2015
- CAP 1470060; EQ File with PI-25A.01-001 has a Deficiency; March 16, 2015
- CAP 1470061; EQ File PI-19.2.001 – Target Rock Valves has a Deficiency; March 16, 2015
- CAP 1470067; EQ File PI-5.7.001 – Unholtz Dickey Pre-Amp has a Deficiency; March 16, 2015
- CAP 1470073; EQ File PI-6.11C.001 – Rockbestos EP Cable has a Deficiency; March 16, 2015
- CAP 1470079; EQ File PI-7.2A.001 – DG O’Brien Electrical Penetrations has a Deficiency; March 16, 2015
- CAP 1470081; EQ File PI-19.1A.001 – ASCO Solenoid Valves has a Deficiency; March 16, 2015
- CAP 1470457; EQ Program File Reconstitution Required; March 17, 2015

- Final Report: Environmental Qualification Program "Deep Dive" Assessment – Prairie Island Nuclear Generating Plant; May 5, 2014
- PMCR 1396981; Credit Completed AOV WOs to PMIDs after 2R28; September 16, 2013 Procedure 2C12.1 AOP4; Alternate Letdown Flowpaths; Revision 3
- Procedure FP-OP-ROM-01; Refuel Outage Scope Selection and Control; Revision 2
- Procedure FP-OP-ROM-01; Refueling Outage Management; Revision 8
- Procedure FP-PE-PM-01; Preventive Maintenance Program; Revision 12
- Unit 2 Control Room Logs; March 5, 2015
- USAR Section 10.2; Chemical and Volume Control System; Revision 33
- USAR Section 4.5; Reactor Coolant Gas Vent System; Revision 29
- WO 456020; PM 37004: EQ Replacement; No Date Provided

4OA5 Other Activities

- NRC Integrated Inspection Report 05000282/2013003; 05000306/2013003
- Letter from J. Lynch, Site Vice President Prairie Island to NRC Document Control Desk; Reply to a Notice of Violation; August 28, 2013
- Letter from K. Davison, Site Vice President to NRC Document Control Desk; Revised Reply to Notice of Violation; November 22, 2013
- PINGP Maintenance Rule Bases/Scoping Document

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ASCO	American Switch Company
CAP	Corrective Action Program
CFCU	Containment Fan Coil Unit
CFR	Code of Federal Regulations
CV	Control Valve
DRP	Division of Reactor Projects
EC	Engineering Change
EDG	Emergency Diesel Generator
EQ	Environmental Qualification
FME	Foreign Material Exclusion
FMEA	Foreign Material Exclusion Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NOUE	Notice of Unusual Event
NOV	Notice of Violation
NRC	U.S. Nuclear Regulatory Commission
OCC	Outage Control Center
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Preventive Maintenance
ppm	Parts Per Million
PRT	Pressurizer Relief Tank
psi	Pounds Per Square Inch
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
SDP	Significance Determination Process
SP	Surveillance Procedure
SSC	Systems, Structures, and Components
SV	Solenoid Valve
TP	Test Procedure
TS	Technical Specification
USAR	Updated Safety Analysis Report
WO	Work Order

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

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

Enclosure:
IR 05000282/2015001; 05000306/2015001
w/Attachment: Supplemental Information

cc w/encl: Distribution via LISTSERV®

DISTRIBUTION w/encl:
Kimyata MorganButler
RidsNrrPMPrairieIsland Resource
RidsNrrDorlLpl3-1 Resource
RidsNrrDirsIrib Resource
Cynthia Pederson
Darrell Roberts
Richard Skokowski
Allan Barker
Carole Ariano
Linda Linn
DRPIII
DRSIII
Jim Clay
Carmen Olteanu
ROPreports.Resource@nrc.gov

ADAMS Accession Number: ML15127A218
☒ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☒ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII		RIII		RIII			
NAME	NShah:mt		KRiemer		ABoland (cover letter)			
DATE	05/04/15		05/04/15		05/06/15			

OFFICIAL RECORD COPY