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

August 11, 2014

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 05000282/2014003; 05000306/202014003

Dear Mr. Davison:

On June 30, 2014, 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 July 17, 2014, with you and other members of your staff.

Two NRC-identified findings and one self-revealed finding, all 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.

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* 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 Public Document Room or from the Publicly Available Records System (PARS) component of 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,

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 05000282/2014003; 05000306/2014003
w/Attachment: Supplemental Information

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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:	05000282/2014003; 05000306/2014003
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	April 1 through June 30, 2014
Inspectors:	K. Stoedter, Senior Resident Inspector P. LaFlamme, Resident Inspector B. Cushman, Reactor Engineer M. Phalen, Senior Health Physicist S. Shah, Reactor Engineer P. Zurawski, Senior Resident Inspector–Monticello
Approved by:	Kenneth Riemer, Chief Branch 2 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000282/2014003; 05000306/2014003; 04/01/2014–06/30/2014; Prairie Island Nuclear Generating Plant, Units 1 and 2; Refueling and Outage 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. These 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 IMC 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. 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 associated non-cited violation Technical Specification 5.4.1 was identified on June 22, 2014, due to the licensee's failure to implement Step 5.5.2.1 of Procedure FP–OP–TAG–01, "Fleet Tagging." Specifically, operations personnel did not reposition valve 2HD–19–1 as stated in Clearance Order 58702. This resulted in Unit 2 operating slightly above the licensed thermal power level for a short period of time. In addition, operations personnel were required to take immediate action to restore Unit 2 power to less than the licensed power limit.

  The inspectors determined that this issue was more than minor because it was associated with the human performance attribute of the Initiating Events cornerstone and impacted the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This issue was of very low safety significance because Question B of IMC 0609, Appendix A, Exhibit 1, "Initiating Events Screening Questions," was answered "No." The inspectors concluded that this issue was cross-cutting in the Human Performance, Avoid Complacency area because operations personnel failed to recognize and plan for the possibility of mistakes by implementing appropriate error reduction tools (H.12). (Section 4OA3.2)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance and an non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," on May 18, 2014, due to the licensee's failure to promptly identify a leak on the 23 containment fan coil unit's lower northeast face as a condition adverse to quality. Corrective actions for this issue included declaring the fan coil unit and the Unit 2 containment inoperable, repairing the leak, performing an extent of condition review, and returning all inoperable equipment to service.

  The inspectors determined that this issue was more than minor because it was associated with the structure, system and components and the barrier performance attributes of the Barrier Integrity cornerstone. The finding also impacted the cornerstone

objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases cause by accidents or events. The inspectors initially assessed the risk of this finding using IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions." Since Question B.1 in Exhibit 3 was answered "Yes," a Region III Senior Reactor Analyst (SRA) continued the risk assessment using IMC 0609, Appendix H, and "Containment Integrity Significance Determination Process." Using Figure 6.1 of IMC 0609, Appendix H, the SRA determined that this finding was a Type B finding and potentially important to large early release frequency. The SRA performed a Phase 2 SDP evaluation and determined that this finding was of very low safety significance because the as-found containment fan coil unit leakage was less than 100 percent of the containment volume/day. The inspectors determined that this finding was cross-cutting in the Human Performance, Avoid Complacency area because individuals failed to recognize and plan for the possibility of latent issues even while expecting successful outcomes (H.12). (Section 1R20.1b(1))

- Green. The inspectors identified a finding of very low safety significance and an non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," on May 20, 2014, due to the licensee's failure to promptly identify a spacer alignment offset on the 21 containment fan coil unit's lower north outlet piping as a condition adverse to quality. As a result, the 21 fan coil unit was subsequently declared inoperable. Corrective actions included establishing acceptance criteria for spacer alignment dimensions, re-aligning the 21 containment fan coil unit lower north outlet flange spacer within the acceptance range, and revising the fan coil maintenance and inspection procedures to incorporate the newly established acceptance criteria.

  The inspectors determined that this issue was more than minor because it was associated with the structures, systems and components and the barrier performance attributes of the Barrier Integrity cornerstone. The finding also impacted the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. This finding was of very low safety significance because Questions B.1 and B.2 provided in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," were answered "No." Specifically, the spacer alignment offset which rendered the 21 FCU inoperable did not represent an actual open pathway in the physical integrity of reactor containment and did not involve an actual reduction in function of hydrogen igniters in the reactor containment. The inspectors concluded that this finding was cross-cutting in the Human Performance, Documentation area because the WO used during the spacer alignment check did not include acceptance criteria to determine whether the spacer was properly aligned (H.7). (Section 1R20.1b(2))

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at full power. Operations personnel reduced Unit 1 reactor power from 100 percent to 40 percent on April 25, 2014, to perform main condenser water box cleaning. Unit 1 was returned to 100 percent power on April 28, 2014. On June 19, 2014, operations personnel lowered Unit 1 reactor power from 100 percent to 25 percent to comply with Technical Specification (TS) requirements following the failure of a safeguards logic relay during surveillance testing. The failed relay was replaced and operations personnel restored the Unit 1 reactor to full power on June 20, 2014. Unit 1 remained at 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period at full power. Operations personnel shut down Unit 2 to Mode 3 on May 18, 2014, to investigate the cause of boric acid accumulation on the 21 reactor coolant pump seal package. The licensee preliminarily determined the cause of the boric acid accumulation to be improper drainage of piping between the #3 reactor coolant pump seal and the reactor coolant drain tank. During the shutdown, the licensee took action to improve the pipe drainage and removed the accumulated boric acid. Operations personnel returned Unit 2 to full power on May 23, 2014. On June 22, 2014, operations personnel lowered Unit 2 reactor power to 89 percent following an explained increase in Unit 2 reactor power. The licensee subsequently determined that the power increase was caused by a human performance error while removing a feedwater heater from service. This issue is discussed in Section 4OA3.2 of this report. Unit 2 returned to full power on June 23, 2014. Unit 2 operated at full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current Power Systems

a. Inspection Scope

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

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

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

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

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

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

b. Findings

No findings were identified.

.2 External Flooding

a. Inspection Scope

During the time periods listed below, operations personnel performed steps within Procedure AB–4, "Flooding," due to the 3-day, predicted Mississippi River level being greater than 678 feet:

- April 14 through April 21, 2014;
- April 29 through May 23, 2014; and
- June 3 through June 30, 2014.

The inspectors evaluated the design, material condition, and procedures for coping with flooding. The evaluation included a review to check for deviations from the descriptions provided in the Updated Safety Analysis Report (USAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also reviewed the abnormal operating procedure

used to mitigating flooding to ensure it could be implemented as written. Documents reviewed are listed in the Attachment to this report. Additional information is included in Sections 4OA2.4 and 4OA2.5 of this report.

This inspection was considered a partial inspection sample since the licensee remained in Procedure AB–4 at the conclusion of the inspection period.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 21 Motor Driven Auxiliary Feedwater Pump and associated piping;
- D6 Emergency Diesel Generator (EDG);
- 21 Safety Injection System; and
- 22 Turbine Driven Auxiliary Feedwater Pump and associated piping.

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

These activities constituted four partial system walkdown samples 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 Detection Zone 12—Relay and Cable Spreading Room Floor;
- Fire Detection Zone 14—Old Computer Room (P250);
- Fire Detection Zone 15—Unit 1 Turbine Building Elevation 715 feet;
- Fire Detection Zone 37—Unit 2 Turbine Building Elevations 679 feet and 695 feet; and
- Fire Detection Zone 44—Unit 2 Turbine Building Elevation 715 feet.

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 Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the licensee's ability to respond to a security event. 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.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On June 17, 2014, the inspectors observed a fire brigade activation for an oil fire located adjacent to the plant heating boiler on the Unit 1 695 feet elevation. Based on this observation, the inspectors evaluated the readiness of the fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them

in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the USAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area(s) to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 1 Auxiliary building crane bay;
- Unit 1 containment spray pump room; and
- Unit 1/2 screen house safety-related areas.

Documents reviewed are listed in the Attachment to this report. This inspection constituted one internal flooding sample as defined in IP 71111.06–05.

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 April 2, 2014, the inspectors observed a crew of licensed operators in the 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 of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On April 28, 2014, the inspectors observed the Unit 1 control room operators performing power ascension activities following a planned power reduction to clean the condenser water boxes. 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 and Emergency Plan actions and notifications.

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:

- Unit 1 Chemical and Volume Control System; and
- Maintenance Rule Evaluations for D1, D2 and D5 performed because of re-scoping of the Maintenance Rule.

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:

- Planned maintenance on the D6 EDG, the 122 and 124 recycle gates and the 12 traveling water screen;
- Planned maintenance on the 13 charging pump, Bus 27, the D5 EDG, and the 121 safeguards traveling screen;
- Planned maintenance on the 21 reactor coolant pump and emergent maintenance on the 21 and 23 containment fan coil units; and
- Emergent maintenance on the 10 bank transformer.

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 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 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 four 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 1424460–Steam Generator Narrow Range Instrument Qualification Evaluation;
- CAP 1425701–Steam Generator Upper Lateral Support Flange Bolt Torque Evaluation;
- CAP 1427907–Instrument Air System Containment Isolation Valve Limit Switches are Non-conforming with Regulatory Guide 1.97;
- Failure of the D2 EDG Lube Oil Keep Warm System;
- OPR 1424399–Shield Building Special Ventilation System Pressure Switch Drift; and
- CAPs 1431557 and 1431287–21 and 23 Fan Coil Unit Leakage and Spacer Alignment Evaluations.

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 six samples as defined in IP 71111.15–05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the following modification:

- D1 and D2 EDG Ventilation Fan Blade Switch Positioner Bypass.

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 one temporary 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 post-maintenance testing activities on the following equipment to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- 13 Containment Fan Coil Unit (FCU) Inlet Valve following a breaker replacement;
- Shield Building Radiation Monitor 2R22 following a power supply replacement;
- D6 EDG following planned preventive maintenance;
- D5 EDG fast start test following relay and hose replacement;
- 21 Reactor Coolant Pump #3 Seal leakage test following planned maintenance;
- 21 and 23 FCU leakage testing following maintenance and repairs; and
- Safeguards Logic Relay 1SI–15X following maintenance.

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 post-maintenance 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 seven 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

a. Inspection Scope

The inspectors evaluated outage activities for a planned Unit 2 maintenance outage that began on May 18, 2014, and continued through May 23, 2014. The outage was performed to correct improper drainage of a pipe between the 21 reactor coolant pump (RCP) seal package and the reactor coolant drain tank. 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, control and monitoring of decay heat removal, control of containment activities, 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

(1) Failure to Identify 23 Containment Fan Coil Leakage as a Condition Adverse to Quality

Introduction: The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” due to the licensee’s failure to promptly identify a leak on the 23 containment FCU’s lower northeast face as a condition adverse to quality.

Description: On May 18, 2014, operations personnel removed the Unit 2 reactor from service to correct improper drainage on a line between the 21 RCP #3 seal and the reactor coolant drain tank. These repairs were performed inside the Unit 2 containment with the reactor in Mode 3 ($k_{eff} < 0.99$ and reactor coolant system temperature greater than or equal to 350^{o} Fahrenheit). Licensee personnel initially entered the Unit 2 containment at 3:00 a.m., to perform radiation surveys and component inspections. Individuals continued to enter the Unit 2 containment as the day progressed to perform maintenance activities and conduct general inspections.

The inspectors entered the Unit 2 containment to inspect the FCUs and conditions inside each reactor coolant pump vault at approximately 7:00 p.m. The inspectors chose these areas for inspection as the licensee had experienced multiple FCU issues during the previous refueling outage and to assess any potential RCS degradation due to the improper drainage discussed above. The inspectors observed water on the floor while inspecting the 23 FCU’s northeast face. The inspectors reported the water to outage

control center (OCC) personnel at approximately 9:30 p.m. At 10:18 p.m., the outage director made the following log entry:

"During the NRC walkdown of the Unit 2 containment the following questions were asked and follow up is needed. A water puddle was observed under the 23 FCU, specifically the corner closest to the personnel airlock and a second issue on the 1 ½" line coming out of the 21 reactor coolant pump on the ladder side there is a leak of 1 drop every 30 seconds."

No corrective action document was initiated to document the inspectors' questions.

At 6:00 a.m., on May 19, 2014, the inspectors discussed the puddle under the 23 FCU with OCC personnel and licensee management. During these discussions the inspectors were told that the water was likely condensation due to pipe sweat since the FCU cooling water temperature was much lower than the containment air temperature. The inspectors asked whether a sample had been taken and analyzed to confirm that the puddle was condensation. No sample had been taken. In addition, there were no plans to take a future sample. This concerned the inspectors since FCU leakage had the potential to impact FCU and Unit 2 containment operability.

The inspectors entered the Unit 2 containment 3 hours later to observe a post-maintenance testing activity on the 21 RCP and perform an additional inspection on the 23 FCU. The inspectors noted that the puddle under the 23 FCU northeast face remained. The inspectors showed the puddle to maintenance and engineering personnel who were also inside containment. Engineering personnel stated that the puddle was condensation. The inspectors challenged this conclusion by asking whether a sample of the water had been taken and analyzed. Initially, engineering personnel stated that a sample had been analyzed. The inspectors challenged this statement since it did not match the previous information provided by the OCC. After contacting the OCC, engineering informed the inspectors that a sample had not been taken or analyzed.

At 11:04 a.m., on May 19, 2014, an OCC member logged that the 23 FCU puddle was being sampled for further analysis. According to the OCC logs, chemistry confirmed the contents of the sample as cooling water (river water) at 12:25 p.m. The operations shift manager declared the 23 FCU and the Unit 2 containment inoperable at 12:36 p.m., due to the cooling water leakage. Specifically, the Unit 2 containment was declared inoperable because the leakage location could become an unmonitored containment leakage path during specific design basis accident conditions. Operations personnel took action to isolate the cooling water from the FCU, remove the FCU from service, and restore Unit 2 containment operability within the 1 hour allowed by the TS. The licensee documented the 23 FCU's inoperability and the failure to promptly identify leakage on the 23 FCU's lower northeast face as a condition adverse to quality as CAPs 1431285 and 1431287. The 23 FCU was satisfactorily returned to service on May 20, 2014.

<u>Analysis</u>: The inspectors considered the licensee's failure to promptly identify the 23 FCU's leakage as a condition adverse to quality to be a performance deficiency that could be evaluated using the SDP. The inspectors considered this finding to be more than minor because it was associated with the SSC and barrier performance attributes of the Barrier Integrity cornerstone. The finding also impacted the cornerstone objective of

providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Attachment 4, "Initial Characterization of Findings." In accordance with Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weakness," the inspectors determined that the boundary best reflecting the dominant risk was the containment boundary. Per Table 3, "SDP Appendix Router," the inspectors answered "No" to all of the questions in each section; therefore, the risk assessment continued with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." This SDP was chosen since the shutdown operations SDP was only used to assess findings that occur during plant operation in Modes 4 through 6.

According to Question B.1 in Exhibit 3, "Barrier Integrity Screening Questions," the finding represented "an actual open pathway in the physical integrity of reactor containment (valves, airlocks, etc.)." Based upon this information, a Region III Senior Reactor Analyst (SRA) continued the risk assessment using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process."

The SRA determined that this was a "Type B" finding. The SRA performed a Phase 1 SDP analysis using Figure 6.1, "Road Map for Large Early Release Frequency (LERF)-based Risk Significance for Evaluation - Type B Findings at Full Power." The SRA reviewed the SSCs listed in Table 6.1, "Phase 1 Screening-Type B Findings at Full Power," and determined that the finding was potentially important to LERF. Prairie Island is a Westinghouse two loop pressurized water reactor (PWR) plant with a large dry containment. The SSCs listed in Table 6.1 for PWR plants with large dry containments included containment penetration seals, isolation valves, and vent and purge systems. The SRA continued the evaluation with a Phase 2 evaluation.

Appendix H, Table 6.2, "Phase 2 Risk Significance–Type B Findings at Full Power," states that "if the as-found leakage rate is less than the values listed in Table 6.2, the finding is Green." For this issue, if the as-found leakage rate from containment to the environment is less than 100% of the containment volume/day, then the issue is Green.

Throughout this exposure period, conservatively chosen to begin on December 28, 2013, to when the unit entered Mode 3 on May 18, 2014, leakage from containment was significantly less than 100% of the containment volume/day. Therefore, the SRA concluded that the total risk associated with this finding was very low and best characterized as Green. The inspectors determined that this finding was cross-cutting in the Human Performance, Avoid Complacency area because individuals failed to recognize and plan for the possibility of latent issues even while expecting successful outcomes (H.12).

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that conditions adverse to quality, such as failures and deficiencies be promptly identified.

Contrary to the above, from May 18 through May 19, 2014, the licensee failed to identify a condition adverse to quality. Specifically, the 23 FCU and the Unit 2 containment were determined to be inoperable due to a lower northeast face corner gasket leak. The

licensee had multiple opportunities to have identified this leak as personnel were inside the Unit 2 containment as part of a planned maintenance outage. In addition, the inspectors notified the licensee about the presence of water under the 23 FCU on May 18, 2014, however no action was taken to investigate the source of the puddle as a condition adverse to quality until approximately 15 hours after the inspectors' notification.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAPs 1431285 and 1431287, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2014003–01: Failure to Identify 23 FCU Leak as a Condition Adverse to Quality)**. Corrective actions for this issue included declaring the fan coil unit and the Unit 2 containment inoperable, repairing the leak, performing an extent of condition review, and returning all inoperable equipment to service.

(2) Failure to Identify 21 Containment Fan Coil Unit Spacer Offset as a Condition Adverse to Quality

Introduction: The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," on May 20, 2014, due to the licensee's failure to promptly identify a spacer alignment offset on the 21 containment FCU's lower north outlet piping as a condition adverse to quality. As a result, the 21 fan coil unit was subsequently declared inoperable.

Description: On May 19, 2014, while working on repairs for the safety-related 23 FCU, the licensee discovered an additional leak on the northeast lower inlet pipe flange which had resulted from improper piping spacer installation. Specifically, the pipe spacer was not centered to the inside diameter of the bolt pattern resulting in inadequate gasket seating surface. In the case of the 23 FCU northeast lower inlet pipe flange, the licensee noted that the spacer ring actually appeared to be resting on the bottom two bolts resulting in improper gasket seating.

On May 20, 2014, following spacer adjustment on the 23 FCU northeast lower inlet piping flange, the licensee performed an extent of condition walk down of all four FCUs in containment. The walk down included a visual inspection of all flanged connections on each FCU. No issues associated with spacer alignment were noted by the licensee following their walk down. The inspectors independently verified proper spacer alignment by visual inspection. During their walk down, the inspectors identified four additional pipe flanges which had associated spacer alignment offset issues. The inspectors noted that the 21 FCU lower north outlet piping flange spacer had the most significant offset that was subsequently determined to be .375 inches low. Additional discussions with operations, maintenance and engineering revealed that acceptance criteria for spacer installation clearance tolerances did not exist. As a result, engineering was tasked to generate acceptance criteria the following shift. Subsequent review performed by engineering determined that the 21 FCU flanged connection could not be relied upon to maintain system integrity. Consequently, the shift manager declared the 21 FCU inoperable at 2:19 a.m., on May 21, 2014. Containment integrity was not impacted by this issue since the spacer misalignment did not result in a containment bypass leakage path during post-accident conditions. The inspectors noted that the other three spacer alignment offset clearances did not impact operability.

The licensee re-aligned the 21 FCU north lower outlet flange spacer per WO 502526 and declared the 21 FCU operable at 12:29 p.m., on May 21, 2014. The licensee subsequently documented the 21 FCU's inoperability and the failure to promptly identify the spacer offset on the 21 FCU's lower north outlet piping flange as CAP 1431557. The inspectors interviewed the maintenance personnel who had performed the spacer alignment visual inspections and noted that the licensee's work package included a visual leak check but did not specify spacer alignment inspection.

Analysis: The inspectors considered the licensee's failure to promptly identify the 21 FCU's spacer alignment offset as a condition adverse to quality to be a performance deficiency that could be evaluated using the SDP. The inspectors considered this finding to be more than minor because it was associated with the SSC and Barrier Performance attribute of the Barrier Integrity cornerstone. The finding also impacted the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

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 Questions B.1 and B.2 provided in IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions," were answered "No." Specifically, the spacer alignment offset which rendered the 21 FCU inoperable did not represent an actual open pathway in the physical integrity of reactor containment and did not involve an actual reduction in function of hydrogen igniters in the reactor containment. The inspectors concluded that this finding was cross-cutting in the Human Performance, Documentation area because the WO used during the spacer alignment check did not include acceptance criteria to determine whether the spacer was properly aligned (H.7).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that conditions adverse to quality, such as failures and deficiencies be promptly identified.

Contrary to the above, on May 20, 2014, the licensee failed to identify a condition adverse to quality. Specifically, the 21 FCU was declared inoperable due to a lower north outlet piping spacer alignment offset. The licensee had multiple opportunities to have identified this spacer offset as personnel were inside the Unit 2 containment as part of a planned maintenance outage with specific instruction to inspect the FCU pipe flange connections.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CAP 1431557, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2014003–02: Failure to Identify 21 FCU Spacer Alignment Offset as a Condition Adverse to Quality)**. Corrective actions included establishing acceptance criteria for spacer alignment dimensions, re-aligning the 21 FCU lower north outlet flange spacer within the acceptance range, and revising the FCU maintenance and inspection procedures to incorporate the newly established acceptance criteria.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- SP 1342–Neutron Flux Monitor Alignment at Reactor Power Monthly Test (routine);
- SP 1902–Weekly Axial Flux Distribution (routine);
- SP 1218–Monthly 4KV Bus 15 Undervoltage Relay Test (routine);
- SP 1130A–Train A Containment Vacuum Breaker Quarterly Test (IST); and
- SP 2088A–Train A Safety Injection Quarterly Test (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 and one inservice testing sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03)

This inspection constituted one complete sample as defined in IP 71124.03–05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the USAR to identify areas of the plant designed as potential airborne radiation areas and any associated ventilation systems or airborne monitoring instrumentation. Instrumentation reviewed included continuous air monitors (continuous air monitors and particulate-iodine-noble-gas-type instruments) used to identify changing airborne radiological conditions such that actions to prevent an overexposure may be taken. The review included an overview of the Respiratory Protection Program and a description of the types of devices used. The inspectors reviewed USAR, TSs, and emergency planning documents to identify location and quantity of respiratory protection devices stored for emergency use.

Inspectors reviewed the licensee's procedures for maintenance, inspection, and use of respiratory protection equipment including self-contained breathing apparatus as well as procedures for air quality maintenance.

The inspectors reviewed any reported performance indicators related to unintended dose resulting from intakes of radioactive material.

b. Findings

No findings were identified.

.2 Engineering Controls (02.02)

a. Inspection Scope

The inspectors reviewed the licensee's use of permanent and temporary ventilation to determine whether the licensee used ventilation systems as part of its engineering controls (in lieu of respiratory protection devices) to control airborne radioactivity. The inspectors reviewed procedural guidance for use of installed plant systems, such as containment purge, spent fuel pool ventilation, and auxiliary building ventilation, and assessed whether the systems were used, to the extent practicable, during high-risk activities.

The inspectors selected installed ventilation systems used to mitigate the potential for airborne radioactivity and evaluated whether the ventilation airflow capacity, flow path (including the alignment of the suction and discharges), and filter/charcoal unit efficiencies, as appropriate, were consistent with maintaining concentrations of airborne radioactivity in work areas below the concentrations of an airborne area to the extent practicable.

The inspectors selected temporary ventilation system setups (high-efficiency particulate air/charcoal negative pressure units, down draft tables, tents, metal "Kelly buildings," and other enclosures) used to support work in contaminated areas. The inspectors assessed whether the use of these systems was consistent with the licensee's procedural guidance and the as-low-as-reasonably-achievable (ALARA) concept.

The inspectors reviewed airborne monitoring protocols by selecting installed systems used to monitor and warn of changing airborne concentrations in the plant and evaluated whether the alarms and setpoints were sufficient to prompt licensee/worker action to ensure that doses were maintained within the limits of 10 CFR Part 20 and the ALARA concept.

The inspectors assessed the licensee established trigger points (e.g., the Electric Power Research Institute's "Alpha Monitoring Guidelines for Operating Nuclear Power Stations") for evaluating levels of airborne beta-emitting (e.g., plutonium–241) and alpha-emitting radionuclides.

b. Findings

No findings were identified.

.3 Use of Respiratory Protection Devices (02.03)

a. Inspection Scope

For those situations where it was impractical to employ engineering controls to minimize airborne radioactivity, the inspectors assessed whether the licensee provided respiratory protective devices such that occupational doses were ALARA. The inspectors selected work activities where respiratory protection devices were used to limit the intake of radioactive materials and assessed whether the licensee performed an evaluation concluding that further engineering controls were not practical and that the use of respirators was ALARA. The inspectors also evaluated whether the licensee established means (such as routine bioassay) to determine if the level of protection (protection

factor) provided by the respiratory protection devices during use was at least as good as that assumed in the licensee's work controls and dose assessment.

The inspectors assessed whether respiratory protection devices used to limit the intake of radioactive materials were certified by the National Institute for Occupational Safety and Health/Mine Safety and Health Administration or were approved by the NRC per 10 CFR 20.1703(b). The inspectors selected work activities where respiratory protection devices were used. The inspectors evaluated whether the devices were used consistent with their National Institute for Occupational Safety and Health/Mine Safety and Health Administration certification or any conditions of their NRC approval.

The inspectors reviewed records of air testing for supplied-air devices and self-contained breathing apparatus bottles to assess whether the air used in these devices met or exceeded Grade D quality. The inspectors reviewed plant breathing air supply systems to determine whether they met the minimum pressure and airflow requirements for the devices in use.

The inspectors selected several individuals qualified to use respiratory protection devices and assessed whether they have been deemed fit to use the devices by a physician.

The inspectors selected several individuals assigned to wear a respiratory protection device and observed them donning, doffing, and functionally checking the device as appropriate. Through interviews with these individuals, the inspectors evaluated whether they knew how to safely use the device and how to properly respond to any device malfunction or unusual occurrence (loss of power, loss of air, etc.).

The inspectors chose multiple respiratory protection devices staged and ready for use in the plant or stocked for issuance for use. The inspectors assessed the physical condition of the device components (mask or hood, harnesses, air lines, regulators, air bottles, etc.) and reviewed records of routine inspection for each. The inspectors selected several of the devices and reviewed records of maintenance on the vital components (e.g., pressure regulators, inhalation/exhalation valves, hose couplings). The inspectors reviewed the Respirator Vital Components Maintenance Program to ensure that the repairs of vital components were performed by the respirators' manufacturer.

b. Findings

No findings were identified.

.4 Self-Contained Breathing Apparatus for Emergency Use (02.04)

a. Inspection Scope

Based on the USAR, TSs, and emergency operating procedure requirements, the inspectors reviewed the status and surveillance records of self-contained breathing apparatuses (SCBAs) staged in-plant for use during emergencies. The inspectors reviewed the licensee's capability for refilling and transporting SCBA air bottles to and from the control room and operations support center during emergency conditions.

The inspectors selected several individuals on control room shift crews and from designated departments currently assigned emergency duties (e.g., onsite search and rescue duties) to assess whether control room operators and other emergency response and radiation protection personnel (assigned in-plant search and rescue duties or as required by emergency operating procedures or the emergency plan) were trained and qualified in the use of SCBAs (including personal bottle change out). The inspectors evaluated whether personnel assigned to refill bottles were trained and qualified for that task.

The inspectors determined whether appropriate mask sizes and types were available for use (i.e., in-field mask size and type match what was used in fit-testing). The inspectors determined whether on-shift operators had facial hair that would interfere with the sealing of the mask to the face and whether vision correction (e.g., glasses inserts or corrected lenses) was available as appropriate.

The inspectors reviewed the past 2-years of maintenance records for select SCBA units used to support operator activities during accident conditions and designated as “ready for service” to assess whether any maintenance or repairs on any SCBA unit’s vital components were performed by an individual, or individuals, certified by the manufacturer of the device to perform the work. The vital components typically were the pressure-demand air regulator and the low-pressure alarm. The inspectors reviewed the onsite maintenance procedures governing vital component work to determine any inconsistencies with the SCBA manufacturer’s recommended practices. For those SCBAs designated as “ready for service,” the inspectors determined whether the required, periodic air cylinder hydrostatic testing was documented and up-to-date, and the retest air cylinder markings required by the U.S. Department of Transportation were in place.

b. Findings

No findings were identified.

.5 Problem Identification and Resolution (02.05)

a. Inspection Scope

The inspectors evaluated whether problems associated with the control and mitigation of in-plant airborne radioactivity were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee’s CAP. The inspectors assessed whether the corrective actions were appropriate for a selected sample of problems involving airborne radioactivity and were appropriately documented by the licensee.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04)

This inspection constituted one complete sample as defined in IP 71124.04–05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the results of Radiation Protection Program audits related to internal and external dosimetry (e.g., licensee's quality assurance audits, self-assessments, or other independent audits) to gain insights into overall licensee performance in the area of dose assessment and focus the inspection activities consistent with the principle of "smart sampling."

The inspectors reviewed the most recent National Voluntary Laboratory Accreditation Program accreditation report on the vendor's most recent results to determine the status of the contractor's accreditation.

A review was conducted of the licensee's procedures associated with dosimetry operations, including issuance/use of external dosimetry (routine, multi-badging, extremity, neutron, etc.), assessment of internal dose (operation of whole body counter, assignment of dose based on derived air concentration-hours, urinalysis, etc.), and evaluation of and dose assessment for radiological incidents (distributed contamination, hot particles, loss of dosimetry, etc.).

The inspectors evaluated whether the licensee had established procedural requirements for determining when external and internal dosimetry was required.

b. Findings

No findings were identified.

.2 External Dosimetry (02.02)

a. Inspection Scope

The inspectors evaluated whether the licensee's dosimetry vendor was National Voluntary Laboratory Accreditation Program accredited and if the approved irradiation test categories for each type of personnel dosimeter used were consistent with the types and energies of the radiation present and the way the dosimeter was being used (e.g., to measure deep dose equivalent, shallow dose equivalent, or lens dose equivalent).

The inspectors evaluated the onsite storage of dosimeters before their issuance, during use, and before processing/reading. The inspectors also reviewed the guidance provided to rad-workers with respect to care and storage of dosimeters.

The inspectors assessed whether non-National Voluntary Laboratory Accreditation Program accredited passive dosimeters (e.g., direct ion storage sight read dosimeters) were used according to the licensee's procedures that provide for periodic calibration, application of calibration factors, usage, reading (dose assessment) and zeroing.

The inspectors assessed the use of active dosimeters (electronic personal dosimeters) to determine if the licensee used a "correction factor" to address the response of the electronic personal dosimeter as compared to the passive dosimeter for situations when the electronic personal dosimeter must be used to assign dose. The inspectors also assessed whether the correction factor was based on sound technical principles.

The inspectors reviewed dosimetry occurrence reports or CAP documents for adverse trends related to electronic personal dosimeters, such as interference from electromagnetic frequency, dropping or bumping, failure to hear alarms, etc. The inspectors assessed whether the licensee identified any trends and implemented appropriate corrective actions.

b. Findings

No findings were identified.

.3 Internal Dosimetry (02.03)

Routine Bioassay

a. Inspection Scope

The inspectors reviewed procedures used to assess the dose from internally deposited nuclides using whole body counting equipment. The inspectors evaluated whether the procedures addressed methods for differentiating between internal and external contamination, the release of contaminated individuals, the route of intake, and the assignment of dose.

The inspectors reviewed the whole body count process to determine if the frequency of measurements was consistent with the biological half-life of the nuclides available for intake.

The inspectors reviewed the licensee's evaluation for use of its portal radiation monitors as a passive monitoring system to determine if instrument minimum detectable activities were adequate to determine the potential for internally deposited radionuclides sufficient to prompt additional investigation.

The inspectors selected several whole body counts and evaluated whether the counting system used had sufficient counting time/low background to ensure appropriate sensitivity for the potential radionuclides of interest. The inspectors reviewed the radionuclide library used for the count system to determine its appropriateness. The inspectors evaluated whether any anomalous count peaks/nuclides indicated in each output spectra received appropriate disposition. The inspector's reviewed the licensee's 10 CFR Part 61 data analyses to determine whether the nuclide libraries included appropriate gamma-emitting nuclides. The inspectors evaluated how the licensee accounts for hard-to-detect nuclides in the dose assessment.

b. Findings

No findings were identified.

Special Bioassay

a. Inspection Scope

The inspectors reviewed and assessed the adequacy of the licensee’s program for in vitro monitoring (i.e., urinalysis and fecal analysis) of radionuclides (tritium, fission products, and activation products), including collection and storage of samples.

The inspectors reviewed the vendor's Laboratory Quality Assurance Program and assessed whether the laboratory participated in an industry recognized cross-check program including whether out-of-tolerance results were resolved appropriately.

b. Findings

No findings were identified.

Internal Dose Assessment–Airborne Monitoring

a. Inspection Scope

The licensee had not performed dose assessments using airborne/derived air concentration monitoring since the last inspection.

b. Findings

No findings were identified.

Internal Dose Assessment–Whole Body Count Analyses

a. Inspection Scope

The inspectors reviewed several dose assessments performed by the licensee using the results of whole body count analyses. The inspectors determined whether affected personnel were properly monitored with calibrated equipment and that internal exposures were assessed consistent with the licensee's procedures.

b. Findings

No findings were identified.

.4 Special Dosimetric Situations (02.04)

Declared Pregnant Workers

a. Inspection Scope

The inspectors assessed whether the licensee informed workers, as appropriate, of the risks of radiation exposure to the embryo/fetus, the regulatory aspects of declaring a pregnancy, and the specific process to be used for (voluntarily) declaring a pregnancy.

The inspectors selected individuals who declared pregnancy during the current assessment period and evaluated whether the licensee's Radiological Monitoring Program (internal and external) for declared pregnant workers was technically adequate to assess the dose to the embryo/fetus. The inspectors reviewed exposure results and monitoring controls employed by the licensee and with respect to the requirements of 10 CFR Part 20.

b. Findings

No findings were identified.

Dosimeter Placement and Assessment of Effective Dose Equivalent for External Exposures

a. Inspection Scope

The inspectors reviewed the licensee's methodology for monitoring external dose in non-uniform radiation fields or where large dose gradients existed. The inspectors evaluated the licensee's criteria for determining when alternate monitoring, such as use of multi-badging, was to be implemented.

The inspectors reviewed dose assessments performed using multi-badging to evaluate whether the assessment was performed consistently with the licensee's procedures and dosimetric standards.

b. Findings

No findings were identified.

Shallow Dose Equivalent

a. Inspection Scope

The inspectors reviewed shallow dose equivalent dose assessments for adequacy. The inspectors evaluated the licensee's method (e.g., VARSKIN or similar code) for calculating shallow dose equivalent from distributed skin contamination or discrete radioactive particles.

b. Findings

No findings were identified.

Neutron Dose Assessment

a. Inspection Scope

The inspectors evaluated the licensee's Neutron Dosimetry Program, including dosimeter types and/or survey instrumentation.

The inspectors reviewed neutron exposure situations (e.g., independent spent fuel storage installation operations or at-power containment entries) and assessed whether: (a) dosimetry and/or instrumentation was appropriate for the expected neutron spectra, (b) there was sufficient sensitivity for low dose and/or dose rate measurement, and (c) neutron dosimetry was properly calibrated. The inspectors also assessed whether interference by gamma radiation had been accounted for in the calibration and whether time and motion evaluations were representative of actual neutron exposure events, as applicable.

b. Findings

No findings were identified.

Assigning Dose of Record

a. Inspection Scope

For the special dosimetric situations reviewed in this section, the inspectors assessed how the licensee assigned dose of record for total effective dose equivalent, shallow dose equivalent, and lens dose equivalent. This included an assessment of external and internal monitoring results, supplementary information on Individual exposures (e.g., radiation incident investigation reports and skin contamination reports), and radiation surveys and/or air monitoring results when dosimetry was based on these techniques.

b. Findings

No findings were identified.

.5 Problem Identification and Resolution (02.05)

a. Inspection Scope

The inspectors assessed whether problems associated with occupational dose assessment were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving occupational dose assessment.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (PI) for Units 1 and 2 for the period from the second quarter of 2013 through the first 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, and NUREG–1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73" definitions and guidance, were used. The inspectors reviewed the operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, CAPs, event reports and NRC Integrated Inspection Reports for the period listed 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.

.2 Mitigating Systems Performance Index—Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI)–Heat Removal System PI for the period from the second quarter of 2013 through the first quarter of 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the operator narrative logs, CAPs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period listed above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. While some problems were identified, the problems did not result in the PI changing color. The NRC planned to review these problems as part of an upcoming 95001 supplemental inspection. This supplemental inspection will review the licensee's actions taken to address inaccurate PI reporting identified by the NRC in 2013. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index—High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI)–High Pressure Injection Systems PI for the period from the second quarter of 2013 through the first quarter of 2014. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the operator narrative logs, CAPs, event reports, MSPI derivation reports, and NRC Integrated Inspection Reports for the period listed above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more

than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. 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. While some problems were identified, the problems did not result in the PI changing color. The NRC planned to review these problems as part of an upcoming 95001 supplemental inspection. This supplemental inspection will review the licensee's actions taken to address inaccurate PI reporting identified by the NRC in 2013. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection systems 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 Physical Protection

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

a. Inspection Scope

As part of the various baseline inspection procedures discussed in 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: Use of Designated Operator to Eliminate Need to Accrue System Unavailability During Surveillance Testing

a. Inspection Scope

Nuclear Energy Institute Document 99–02, "Regulatory Assessment Performance Indicator Guidelines," provides NRC licensees with guidelines that must be met as part of the PI reporting process. Appendix F of NEI 99–02 allowed licensees to exclude system unavailability hours accrued during surveillance testing from their PI reports if a designated operator could take action to restore the system during an emergency. However, NEI 99–02 also stated that the designated operator must be stationed locally for the sole purpose of performing the restoration actions, the actions must be proceduralized, and the actions needed to consist of only one action or a few simple actions.

While observing cooling water pump surveillance testing in 2012, the inspectors identified that the licensee was not properly adhering to industry guidelines regarding the use of designated operators. Specifically, the inspectors observed the designated operator performing other activities during the testing rather than being dedicated to performance of the system restoration actions. As a result, the inspectors questioned the accuracy of the licensee's cooling water system PIs. The inspectors reviewed the licensee's PI bases document and system unavailability data for each of the safety-related systems monitored by the NRC's PI program. The inspectors identified similar concerns with the auxiliary feedwater and residual heat removal systems. The licensee reviewed the inspectors' concerns and provided updated PI data to the NRC. While the failure to report accurate PI data to the NRC was a violation of 10 CFR 50.9, this violation was considered minor as none of the PIs changed color.

During the first quarter of 2014, the inspectors observed surveillance testing on multiple systems to ensure that the licensee was complying with the guidance provided in NEI 99–02 regarding the use of designated operators. The inspectors also reviewed a sampling of PI system unavailability information to assess whether the licensee was properly reporting this data to the NRC. Documents reviewed are listed in the Attachment to this report.

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 External Flooding Strategy Implementation

a. Inspection Scope

While reviewing actions taken to address Licensee Event Report 2013–002, "Unanalyzed Condition—Inadequate Fuel Oil Replenishment," the inspectors discovered a document which indicated that prior to 2012 the licensee may not have had adequate time to implement their external flooding mitigating strategy in response to a design basis flood. The inspectors were concerned with the information provided in this document since the licensee had formally communicated their ability to implement the external flooding mitigation strategy in a November 26, 2012, letter to the NRC.

The inspectors reviewed corrective action documents, external flooding procedures, and the results of the licensee's external flooding walkdowns performed following the tsunami at the Fukushima Dai-ichi plant in Japan. The inspectors also discussed the external flooding strategy with operations, engineering, maintenance, and work management personnel. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified. However, the inspectors were concerned with the licensee's initial lack of urgency in ensuring the ability to effectively implement the external flooding strategy.

Normal Mississippi River level at the Prairie Island Nuclear Generating Plant is approximately 674 feet. Operations personnel enter the abnormal procedure for flooding, AB–4, when the 3-day predicted river level is 678 feet or greater. Actions provided in Procedure AB–4, were organized based upon the 3-day predicted river level. These actions were completed to ensure plant safety was maintained during flooding conditions.

In 2012, the licensee performed inspections of their external flooding mitigating equipment and strategy to ensure that Prairie Island maintained the capability to respond to a design basis flood of the Mississippi River. The flooding related inspection results were communicated to the NRC by letter dated November 26, 2012. This letter included the Prairie Island Nuclear Generating Plant External Flooding Walkdown Report. Page 21 of the report stated that the licensee performed walkthroughs of the actions provided in Revision 41 of Procedure AB–4. These walkthroughs consisted of reviewing the time required to complete actions, personnel requirements and availability, and any impacts due to adverse conditions. The licensee also stated that installation of the flood

doors and bulkheads was a critical action when the 3-day predicted river level was greater than or equal to 692 feet.

The inspectors reviewed the External Flooding Walkdown Report in detail and found that the licensee had 4-days to shutdown both reactors, install the flood doors and bulkheads, and allow any caulk used during the door/bulkhead installation to cure once the 3-day predicted level was 692 feet or greater. The installation of the doors and bulkheads was necessary prior to the river level reaching 695 feet (ground level) or greater to ensure that safety-related equipment was not rendered inoperable due to river water intrusion into plant buildings. Page 22 of the report provided to the NRC stated that several enhancements were suggested to improve Procedure AB–4's clarity, increase overall preparedness, and streamline actions needed to protect structure, system, and components important to safety. However, none of these enhancements were considered deficiencies that impacted the licensee's ability to implement the external flooding strategy.

As part of the licensee event report (LER) review discussed above, the inspectors reviewed the Prairie Island Nuclear Generating Plant Flood Hazards Walkdown Report. This report was completed by personnel that performed the inspections discussed in November 26, 2012, letter to the NRC. Page 24 of the Flooding Hazards Walkdown Report initially stated that the licensee needed greater than 4-days to install the flood doors and bulkheads. However, this was discounted since the personnel believed that the licensee would assign additional people to the door installation activities to ensure they were installed within the required time.

The inspectors reviewed the CAP database and found that the Nuclear Oversight Department (NOS) initiated CAP 1397510 on September 19, 2013, because the flood door and bulkhead installation lacked a documented timing study to show that they could be installed in 4-days or less. The CAP documented that Engineering Change (EC) 21069, "Engineering Review of Fukushima Seismic and Flooding Walkdown Reports," stated that up to 5.5-days may be needed to install the doors and bulkheads. This EC also provided recommendations to improve the overall time. These recommendations were viewed as suggestions to improve AB–4. No one questioned the ability to effectively implement the external flooding strategy.

The inspectors also found that the licensee had completed a revised timing study on October 4, 2013. While the overall installation times improved, they were still beyond the 4-days provided in Procedure AB–4. However, no actions were taken to address this issue because personnel viewed the revised timing study as evaluating "conservative/worst case scenarios." The inspectors were concerned by this statement since the conditions evaluated were based upon the maximum permissible flooding scenario discussed in the Updated Safety Analysis Report.

In January 2014, the inspectors challenged licensee management on Prairie Island's ability to install the flood doors and bulkheads within 4-days. The inspectors also discussed the accuracy of information provided to the NRC in the November 26, 2012, letter. Specifically, the inspectors requested information to support the licensee's conclusion that the flood doors and bulkheads could be installed within 4-days. After waiting 3-weeks and receiving no information that supported the timely installation of flood doors and bulkheads, the inspectors informed the licensee that this issue was

going to be considered a performance deficiency and that actions were being taken to address the significance of the issue.

The licensee documented the inspectors concerns via CAP 1418092. In addition, the licensee directed that a documented flood door and bulkhead installation timing study be performed. This timing study consisted of timing the flood door and bulkhead installation using the guidance provided in AB–4, Revision 41 (revision in existence when 2012 flooding walkdowns were completed) and the minimum number of resources. A small number of doors/bulkheads were unable to be installed since the installation created an internal flooding mitigating issue when the reactors were operating.

Before beginning the timing study, the licensee assumed that the first 24 hours of the 4-day installation period would be used to shut down the reactors. In addition, the last 24 hours was assumed to be time needed for any caulk applied during the door/bulkhead installation to cure. This resulted in the doors/bulkheads needing to be installed within 48-hours. The inspectors reviewed and timed the installation of each door/bulkhead. The total installation time calculated by the inspectors was approximately 38-hours. Since this time was less than the 48 hours assumed by the licensee, and the total installation time (including shutting the units down and caulk curing time) was less than 4-days, the inspectors concluded that the licensee could effectively implement their flooding strategy and a performance deficiency did not exist. In addition, the information provided to the NRC in the November 26, 2012, letter was accurate.

.5 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee’s CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors’ review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors’ review nominally considered the 6-month period of January 2014 through June 2014, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP process such as items included in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee’s CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee’s trending reports were reviewed for adequacy.

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

b. Findings

No findings were identified. However, the inspectors identified two noteworthy trends based upon the documentation reviewed.

Trend #1—Documentation and Resolution of Mode Restraint Actions

Pressurized water reactors are normally operated in modes referred to as Modes 1 through 6. The mode definitions are based upon reactor coolant system temperature and whether the reactor is critical or not. Modes 1 and 2 are used when the reactor is critical. Shutdown conditions are defined as Modes 3 through 6. During times the reactor was not operating in Mode 1, the operations department assigned actions for completion (called mode restraints) to ensure that all technical specification (TS) equipment requirements were met prior to changing modes.

While conducting the maintenance rule inspections documented in Section 1R12 of this report, the inspectors reviewed CAP 1400888, "Surveillance Procedure (SP) 2100 not done in 2R28." This CAP documented that the Unit 2 turbine driven auxiliary feedwater (TDAFW) system TS surveillance activities scheduled for completion in October 2013 could not be performed due to plant conditions. The CAP initiator recommended that the operations department initiate a mode restraint to ensure that the system was properly tested prior to returning the system to service. The initiator also recommended that the next Unit 2 TDAFW surveillance activity (scheduled for December 2013) be annotated to ensure that the October 2013 testing activities were completed as part of this activity.

The inspectors reviewed work order (WO) 488192 which documented the December 2013 Unit 2 TDAFW surveillance results. The inspectors determined that the October 2013 surveillance requirements were not included as part of the WO. In addition, the inspectors found that the operations department had not implemented a mode restraint to ensure that the October 2013 testing requirements were met prior to returning the Unit 2 TDAFW system to service following the refueling outage activities. As a result, the inspectors were concerned that the Unit 2 TDAFW system may be inoperable since the October 2013 TS required surveillance activities may not have been completed.

The inspectors discussed their concern with the operations department surveillance coordinator. The coordinator documented the inspectors' concern as CAP 1430125. During a subsequent review, the operations department identified that the October 2013, Unit 2 TDAFW surveillance requirements were performed satisfactorily on October 18, 2013, as part of WO 409536. This was not immediately recognized since WO 409536 failed to contain a mode restraint action. The inspectors reviewed the WO 409536 results and concluded that the October 2013 surveillance requirements were met and that the Unit 2 TDAFW system was operable. However, the inspectors remained concerned regarding the mode restraint implementation process.

On May 18, 2014, the inspectors observed a discussion between a system engineer and OCC personnel regarding the possible presence of boric acid underneath insulation for a 21 RCP tie rod. Following this observation, the inspectors believed that the insulation would be removed and an inspection would be performed to verify that the boric acid had not adversely impacted the tie rod's structural integrity.

The following morning the inspectors discussed insulation removal and inspection activities with OCC personnel. The OCC personnel informed the inspectors that the inspection had been completed without removing the insulation. The inspectors were concerned by this information since it was not clear how an inspection could be

performed on a component covered with insulation. The inspectors requested a copy of the inspection results which were documented in CAP 1431205. The inspectors determined that the boric acid evaluation attached to CAP 1431205 was generically written and failed to mention specific tie rod inspection results. Due to the lack of information, the inspectors were unable to conclude that a satisfactory tie rod inspection was completed. The inspectors communicated this information to OCC personnel.

Later that morning, the inspectors attended a meeting to observe licensee personnel review startup issues and mode restraint actions. During this meeting, operations personnel stated that all mode restraint actions were complete. The inspectors questioned the accuracy of this statement based upon the previous issues discovered with evaluating the integrity of the 21 RCP tie rod. Through discussions with operations personnel present at the meeting, the inspectors learned that the operations department was unaware of the tie rod issues because neither a corrective action document nor a mode restraint action had been initiated. The licensee subsequently initiated a CAP, removed the insulation, performed the inspection, and documented the specific inspection results in CAP 1431342. The inspectors reviewed the inspection results and had no concerns. However, the inspectors considered this to be an additional example of a lack of rigor in implementing the mode restraint process. The licensee was developing actions to address this item at the conclusion of the inspection period.

<u>Trend #2—Lack of Timeliness in Resolving External Flooding Related Issues</u>

As discussed in Section 4OA2.4 of this report, the licensee had not demonstrated a sense of urgency after multiple groups questioned the ability to implement the external flooding strategy within the required time. Through the daily review of CAPs and attendance at meetings, the inspectors became aware of other external flooding related equipment issues which lacked timely resolution by the licensee.

<u>Heating Boiler Oil Storage Tank Pump Issues</u>

In October 2013, the licensee initiated CAP 1395969 to document that the 121 heating boiler oil storage tank (HBOST) fuel oil transfer pump stopped pumping during a fuel oil transfer. Although this pump was non-safety related, it is one of two pumps used to transfer fuel oil from the heating boiler oil storage tanks to the emergency diesel generator (EDG), the diesel driven cooling water pump diesel, and the diesel driven fire pump oil storage tanks. In addition, these pumps were used during an external flooding event to ensure adequate fuel oil continued to be supplied to the EDGs. The licensee initially attempted to repair the pump but was unsuccessful. On March 6, 2014, the licensee initiated CAP 1421516 to document that the 122 HBOST fuel oil transfer pump would not stay running during routine testing. At the time CAP 1421516 was written, the 121 HBOST fuel oil transfer pump remained non-nonfunctional. The inspectors reviewed the maintenance work history for the 121 HBOST and found that no action had been taken to repair this pump other than the initial attempt in October 2013.

The inspectors discussed the condition of both HBOST pumps with operations personnel. The licensee documented the inspectors concerns as discussed in CAP 1421608. The licensee was able to quickly repair the 122 HBOST pump, but parts were required to be ordered to repair the 121 HBOST. In addition, the broken 121 HBOST fuel oil transfer pump was not identified as a component needed to ensure the licensee's readiness for an external flooding condition. The 121 HBOST fuel oil transfer

pump was subsequently repaired on May 30, 2014. However, the inspectors concluded that the 5 months needed to repair the pump was excessive, was reflective of a poor sensitivity to repairing flooding related equipment, and demonstrated an implementation weakness in the licensee's work management program.

External Flooding Related Doors

While performing the external flooding timing study in March 2014, the licensee again identified that Door 73 and Door 46 required maintenance. The licensee initiated CAP and work requests when the door material deficiencies were identified and placed both doors on the list of operational concerns. Although, operations personnel assessed both doors as functional but degraded flood barriers, neither door had been repaired and/or replaced at the conclusion of the inspection period. The inspectors were informed that the Door 73 replacement was delayed due to the need to order a replacement door. In addition, the door vendor stated that it would take approximately 14-weeks for the new door to arrive at Prairie Island. Repair activities on Door 46 were also initially delayed due to confusion regarding what, if any, parts were needed to perform the repair.

The inspectors reviewed the CAP database and the maintenance work histories for Doors 73 and 46. The inspectors found that both doors were identified as needing maintenance during the performance of SP 1293, "Inspection of Flood Control Measures," on February 4, 2014. The licensee documented the condition of the doors in CAPs 1417383 and 1417394 respectively. These CAPs were closed to minor Work Requests (WR) 100424 and 100427. The inspectors reviewed the WR information in Passport and noted that the WR job type listed on both WRs was a deficient issue with low consequence. As a result, no work had been performed or planned prior to the flooding timing study performed in March 2014. The inspectors considered the decision to code the WRs as deficient issues with low consequences to be a weakness within the process used to prioritize and code work requests. The inspectors also noted that the licensee's decision to perform SP 1293 in late winter resulted in not allowing enough time (greater than 14-weeks) to order, receive and replace doors prior to the April flooding season. Door 46 was scheduled for repair in July 2014. The licensee planned to receive replacement door for Door 73 in August 2014.

Unsealed Electrical Pull Boxes

In August 2013, the licensee identified several electrical pull boxes containing conduit which were not adequately sealed with flood rated seals as indicated in plant drawings. As a result, water could potentially enter plant areas through the unsealed pull boxes during an external flooding event. The inspectors reviewed the WOs associated with repairing the pull boxes and found that none of them had been repaired. The WO statuses were taken to "hold for approval" in June 2014. However, the inspectors were unable to determine when the WOs were scheduled for completion. The inspectors reviewed the CAPs that documented the condition of both pull boxes (CAPs 1395149 and 1401947) and found that these were not scheduled for closure until August and March 2015 respectively. Based upon this information, the inspectors determined that the pull boxes would not be repaired in the immediate future. The licensee was reviewing this issue at the conclusion of the inspection period.

The licensee recently completed an assessment of their work management process. Multiple actions were developed to improve the work management process. The inspectors determined that these actions should ensure that work on external flooding mitigation equipment would receive a higher priority rating and be repaired in a timely manner.

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

.1 Unit 1 Technical Specification Required Shutdown Started Following Failed Surveillance Test

a. Inspection Scope

On June 19, 2014, the licensee experienced a relay failure while performing surveillance testing on the Unit 1 Train A, safeguards logic system. Since the relay was unable to be repaired within the TS allowed time, the licensee began shutting down Unit 1. The inspectors monitored the actions associated with repairing the relay from within the relay room to ensure that the repairs were completed as directed by the WO. The inspectors also observed Unit 1 shut down activities from the control room to ensure that the operators were conducting the power manipulations as directed by the reactivity plan and procedures. Unit 1 reactor power was approximately 25 percent when the relay was tested and returned to service. The inspectors reviewed the post-maintenance testing to ensure that the new relay adequately performed its required safety function. Once the relay repairs were completed, TS allowed the licensee to increase reactor power to full power levels. The inspectors observed the power ascension activities to ensure that operations personnel performed the reactivity manipulations in accordance with procedural requirements. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.2 Unit 2 Transient Due to Failure to Follow Equipment Tagout Instructions

a. Inspection Scope

On June 22, 2014, Unit 2 entered 2C1.4 AOP1, “Rapid Power Reduction,” due to an unexplained change in reactor power. The inspectors interviewed operations personnel, reviewed plant process computer information, and reviewed procedures to determine the cause of the power increase. The inspectors also reviewed actions within 2C1.4 AOP1 to assess whether the control room operators responded properly to this event.

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 TS 5.4.1 was identified for the failure to establish, implement, and maintain procedures governing the equipment control (locking and tagging) process. Specifically,

operations personnel failed to comply with Step 5.5.2.1 of Procedure FP–OP–TAG–01, “Fleet Tagging,” while performing Clearance Order 58702. This resulted in reactor power increasing slightly above the licensed power limit for a short period of time. In addition, operations personnel were required to take immediate manual action to restore Unit 2 reactor power to less than the licensed power limit.

Description: On June 22, 2014, a non-licensed operator (NLO) received a pre-job briefing and was directed to isolate control valve CV–31062 (25A feedwater heater dump valve to the main condenser) using Clearance Order 58702. This clearance order contained three steps. The first step was performed without error. However, the NLO experienced difficulty when attempting to re-position manual isolation valve HD–19–1 to the closed position as directed by the clearance order’s second step. Due to the large amount of effort exerted while attempting to fully re-position HD–19–1, the NLO decided to complete the third clearance order step even though valve HD–19–1 was not fully closed.

The third clearance order step directed that the air supply valve to CV–31062 be closed. As the air supply valve was closed, CV–31062 failed open (as designed) due to the loss of air. This resulted in a loss of secondary side efficiency and an increase in Unit 2 reactor power above the licensed power limit for approximately one minute. Control room personnel immediately entered 2C1.4 AOP 1 and lowered reactor power to 90 percent to stabilize plant conditions.

As discussed in Regulatory Issues Summary 2017–21, Revision 1, “Adherence to Licensed Power Limits,” the NRC recognizes that licensees may momentarily operate the reactor above the licensed power limit due to unforeseen circumstances such as human error or equipment failure. In these cases, the NRC has concluded that these situations constitute minor violations of the reactor operating license as long as immediate actions were taken to reduce reactor power to less than the licensed power limit.

The inspectors determined that immediate actions were taken to lower Unit 2 reactor power to less than the licensed power limit. However, the NLO failed to comply with the requirements specified in Procedure FP–OP–TAG–01. Specifically, Step 5.5.2.1 stated that the tagger shall position equipment/components as specified on the clearance order. Contrary to this requirement, the NLO failed to re-position valve 2HD–19–1 to the closed position as directed in Step 2 of Clearance Order 58702 prior to completing Step 3 of the clearance order.

Analysis: The inspectors determined that the failure to follow Step 5.5.2.1 of FP–OP–TAG–01 was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because it was associated with the human performance attribute of the Initiating Events cornerstone and impacted the objective of limiting the likelihood of 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 this issue was of very low safety significance because Question B of IMC 0609, Appendix A, Exhibit 1, “Initiating Events Screening Questions,” was answered “No.” The inspectors concluded that this issue was cross-cutting in the Human Performance, Avoid Complacency area because

operations personnel failed to recognize and plan for the possibility of mistakes by implementing appropriate error reduction tools (H.12).

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 1.c of Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, requires procedures for equipment control (e.g., locking and tagging). Procedure FP–OP–TAG–01, "Fleet Tagging," was the procedure used by the licensee to establish, implement and maintain the equipment control process. Step 5.5.2.1 of Procedure FP–OP–TAG–01 stated that the tagger shall position equipment/components as specified on the clearance order.

Contrary to this requirement, on June 22, 2014, the licensee failed to position equipment/component as specified on the clearance order. Specifically, a NLO failed to fully re-position valve 2HD–19–1 to the closed position as directed in Step 2 of Clearance Order 58702 prior to completing Step 3 of the clearance order. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1435709, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000306/2014003–03: Failure to Follow Safety Tagging Procedure Results in Unit 2 Power Change)**. Corrective actions for this issue included ensuring components covered by Clearance Order 58702 were in the correct position, reviewing this event and the fleet tagging requirements with operations personnel, and implementing additional oversight of operations activities to improve operator performance.

.3 (Closed) Licensee Event Report 05000282/2013–002–00; 05000306/2013–002–00: Unanalyzed Condition—Fuel Oil Inadequate Replenishment

On November 18, 2013, the licensee submitted the above LER to the NRC to document a potential unanalyzed condition regarding the ability to replenish EDG fuel oil during external flooding conditions. The licensee completed an additional review of fuel oil consumption during an external flooding event assuming the EDGs were loaded at their expected external flood load condition. In addition, the diesel driven cooling water pumps (DDCLPs) were assumed to be operating at their continuous loading levels for the duration of the flooding event (approximately 14-days). The revised analysis showed the adequate fuel oil would be available onsite to allow for approximately 24-days of EDG and DDCLP operation. Since this time was greater than the 14 day external flooding event discussed in the USAR, an unanalyzed condition did not exist. As a result, this LER was cancelled by the licensee via a letter to the NRC dated June 9, 2014. The inspectors reviewed the revised analysis and the cancellation letter. No concerns were identified. Documents reviewed are listed in the Attachment to this report. This LER is closed.

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

4OA5 Other Activities

.1 Review of Alternate Source Term Amendment Implementation Issues

a. Inspection Scope

The inspectors interviewed regulatory affairs personnel and reviewed the information provided in CAP 1425039, “Alternate Source Term Amendment Gap Analysis,” and CAP 1424460, “NRC License Amendment Implementation Requirement Not Met,” to determine the circumstances which led to the licensee not completing an amendment implementing requirement prior to implementing the alternate source term (AST) amendment.

b. Findings

Introduction: An unresolved item (URI) was documented by the inspectors due to the licensee identification of a failure to meet a license amendment implementing requirement on March 27, 2014.

Discussion: In 2011 the licensee submitted an operating license amendment request to the NRC to adopt a new source term. This amendment was referred to as the AST amendment. The licensee performed and submitted radiological calculations to the NRC for review as part of the amendment process. The calculation results were used to show that adoption of the new source term was safe and did not adversely impact the public. The licensee’s radiological analysis for the steam generator tube rupture (SGTR) event made assumptions regarding whether or not the steam generators over fill. These assumptions were partially based upon the performance of the steam generator water level narrow range instruments since these instruments are used to determine whether any subsequent radiological release would be contained in steam, a combination of steam and water, or just water.

Since the licensee relied upon the steam generator water level narrow range instruments as an indication of steam generator over fill (both pre-AST and post-AST), the NRC required that the instruments comply with Regulatory Guide (RG) 1.97. During the NRC’s AST amendment review, an NRC reviewer raised questions regarding the qualification of the steam generator water level narrow range instrumentation. Specifically, the reviewer questioned whether the instruments complied with RG 1.97, Revision 2, requirements. The licensee found that the instruments in question were not included in the current RG 1.97 program. The licensee responded to the NRC reviewer’s question via a Request for Additional Information (RAI) response dated December 8, 2011. Within the RAI, the licensee identified a new commitment to the NRC which stated the following:

- “The Prairie Island Nuclear Generating Plant will revise the plant design and licensing bases to indicate that the steam generator water level narrow range instrumentation is required to meet Regulatory Guide 1.97, Revision 2, requirements. This commitment will be completed prior to implementation of the AST license amendment.”

The NRC issued the AST amendment on January 23, 2013. The amendment restated the commitment provided above. However, the NRC listed the commitment as an implementation requirement that needed to be completed prior to implementing the AST

amendment. The AST amendment was required to be implemented within 90 days following the fall 2013, Unit 2 refueling outage.

The Unit 2 refueling outage ended on approximately January 1, 2014. Although the licensee implemented the AST amendment within 90-days of the end of the outage, the licensee identified on March 27, 2014, that they had not revised the plant design or licensing bases to indicate that the steam generator water level narrow range instruments were compliant with Regulatory Guide 1.97, Revision 2. The licensee also indicated that a modification may be required to achieve compliance.

The licensee initiated CAPs 1424460 and 1425033 to document this issue. The licensee revised their Technical Requirements Manual to include pre-AST requirements and ensured that all previous testing requirements were met. The inspectors reviewed the manual revision and the testing data and had no concerns. At the conclusion of the inspection period, the licensee was determining whether they planned to move forward with actions needed to make the steam generator water level narrow range instruments compliant with RG 1.97, Revision 2, or propose new actions to the NRC for review and approval. Since the licensee's course of action was unclear, and the NRC's acceptance of the licensee's actions was unknown, the inspectors considered this issue to be unresolved pending the NRC's review of the licensee's future actions **(URI 05000282/2014003–04; 05000306/2014003–04: Failure to Meet Alternate Source Term Amendment Implementing Requirement)**.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 17, 2014, the inspectors presented the inspection results to Mr. K. Davison, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the areas of in-plant airborne radioactivity control and mitigation and occupational dose assessment with Mr. S. Sharp, Director of Site Operations, on May 23, 2014.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

K. Davison, Site Vice President
S. Sharp, Director—Site Operations
J. Hallenbeck, Site Engineering Director
C. Younie, Plant Manager
T. Allen, Assistant Plant Manager
J. Anderson, Regulatory Affairs Manager
J. Boesch, Production Planning Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
H. Butterworth, Nuclear Oversight Manager
F. Calia, Business Support Manager
C. Childress, Maintenance Manager
J. Corwin, Security Manager
K. DeFusco, Emergency Preparedness Manager
D. Gauger, Chemistry/Environmental Manager
B. Meek, Safety and Human Performance Manager
E. Rogers, Corrective Action Program Manager
J. Ruttar, Operations Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Projects Branch 2
S. Wall, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000306/2014003–01	NCV	Failure to Identify 23 FCU Leak as a Condition Adverse to Quality
05000306/2014003–02	NCV	Failure to Identify 21 FCU Spacer Alignment Offset as a Condition Adverse to Quality
05000282/2014003–03	NCV	Failure to Follow Safety Tagging Procedure Results in Unit 2 Power Change
05000282/2014003–04; 05000306/2014003–04	URI	Failure to Meet Alternate Source Term Amendment Implementing Requirement

Closed

05000306/2014003–01	NCV	Failure to Identify 23 FCU Leak as a Condition Adverse to Quality
05000306/2014003–02	NCV	Failure to Identify 21 FCU Spacer Alignment Offset as a Condition Adverse to Quality
05000282/2014003–03	NCV	Failure to Follow Safety Tagging Procedure Results in Unit 2 Power Change
05000282/2013–002–00; 05000306/2013–002–00	LER	Unanalyzed Condition—Fuel Oil Inadequate Replenishment

Discussed

None

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.

1R01 Adverse Weather Protection

- 4.16 Kilovolt Electrical System Health Report; April 7, 2014
- 480 Volt Electrical System Health Report; April 14, 2014
- AB-7; Station Auxiliary Load Reduction; Revision 7
- C20.3 AOP 1; Evaluating System Operating Conditions When Security Analysis is Out of Service; Revision 15
- C20.3 AOP 12; Grid Voltage or Frequency Disturbances; Revision 6
- C20.3; Electrical Power System Security Analysis; Revision 23
- CAP 1430035; Tornado Missile Hazards in Substation; May 8, 2014
- D1 Diesel Generator System Health Report; April 30, 2014
- D2 Diesel Generator System Health Report; April 30, 2014
- D5 Diesel Generator System Health Report; April 29, 2014
- D6 Diesel Generator System Health Report; April 29, 2014
- Plant Substation System Health Report; April 28, 2014

1R04 Equipment Alignment

- 2C37.10-1; D5/D6 DSL Gen Bldg. HVAC; Revision 9
- C1.1.18-2; SI, CS, CA & HC System Checklist Unit 2; Revision 49;
- C1.1.20.7-13; D6 Diesel Generator Valve Status; June 9, 2011
- C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 12
- CAP 1394798; Auxiliary Feedwater Pump Bearing High Temperature ERCS Alarm Engineering Change Closed but not Installed; August 23, 2013
- CAP 1400692; 22 Turbine Driven Auxiliary Feedwater Governor Replacement Delayed due to Availability; October 8, 2013
- CAP 1400888; SP 2100 not Done in 2R28 – How Will October Only Items be Done; October 10, 2013
- CAP 1401593; Failure Rate of Air Operated Valves during RF028; October 12, 2014
- CAP 1412080; SP 2301 Time Delay Longer than Expected; December 29, 2013
- CAP 1412733; 22 Turbine Driven Auxiliary Feedwater Pump Inboard Turbine Casing Drain Increased Leakoff; December 30, 3013
- CAP 1412818; 22 Turbine Driven Auxiliary Feedwater Pump Turbine Outboard Bearing Temperature Greater than 203 Degrees; December 30, 2013
- CAP 1412819; Auxiliary Feedwater Pump Testing per SP 2330 Outboard Bearing at 204 Degrees; December 30, 2013
- CAP 1414321; SP 2101 Mistakenly Credited for Close Test of AF-15-12; January 16, 2014
- CAP 1422701; CV-31999 Open Stroke Time Increasing during SP 2102; March 11, 2014
- CAP 1430125; SP 2100 Quarterly Requirements for 4Q13 not Credited Properly; May 9, 2014
- Checklist C28-18; 22 Turbine Driven Auxiliary Feedwater Pump; Revision 9
- Checklist C28-7; Auxiliary Feedwater System Unit 2; Revision 54
- SP 2088A; Train A Safety Injection Quarterly Test; March 25, 2013
- System Prestart Checklist C28-16; 21 Motor Driven Auxiliary Feedwater Pump; Revision 7

- WO 477700-01; SP 2100 - 21 Motor Driven Auxiliary Feedwater Pump Monthly Test; December 4, 2013
- WO 488912-01; SP 2100 – 21 Motor Driven Auxiliary Feedwater Pump Monthly Test; December 9, 2013

1R05 Fire Protection

- 5AWI 3.13.2; Fire Prevention; Revision 23
- 5AWI 8.5.0; Housekeeping and Material Condition; Revision 11
- CAP 01429665; Fire Reported Near Distribution Center; May 6, 2014
- F5, Appendix A; Fire Protection Zones; Revision 30
- F5, Appendix F; Fire Hazard Analysis; Revision 28
- Fire Drill Critique Report; Crew #4; June 19, 2014
- RPIP 1028; Respiratory Protection Checks; Revision 20

1R06 Internal Flooding

- CAP 1434752; Large Amount of Water in Aux Building Truck Isle; June 15, 2014
- CAP 1434754; Aux Building Rood Leak; June 15, 2014
- CAP 1434777; Rainwater Leakage Into Aux Builingdg Filling Waste Holdup Tank > 11%; June 15, 2014
- CAP 1434779; Excessive Rainwater Entering Aux Building; June 15, 2014

1R11 Licensed Operator Requalification

- P9114SE-0201; LOR Cycle 14B Simulator Evaluation; Revision 1
- FP-OP-COO-19; Log-keeping Revision 1

1R12 Maintenance Effectiveness

- CAP 1348044; D1 Control Side Turbo Charger Gasket Leak; August 13, 2013
- CAP 1348106; D2 Exhaust Manifold Fire; August 14, 2013
- CAP 1350317; D5 voltage would not adjust during startup per SP 2093; September 7, 2012
- CAP 1363667; Unable to reach full load on D1 test run, need to adjust gov.; December 18, 2012
- CAP 1394475; Radiation Monitoring Maintenance Rule Basis Document Rev., now a(1); August 23, 2013
- CAP 1394758; Boric Acid Leak on VC-369-11 Connection
- CAP 1401848; D1 GEN forced shutdown due to LO Cooler oil leak; October 15, 2013
- CAP 1402431; CS-50009 Green light NOT LIT
- CAP 1402435; D5 DSL room cooling fan did not start as expected
- CAP 1413321; RCS Leak on Unit 1
- CAP 1420122; MRule (A)(1) Action Plan Development and Action Plan Goal Setting Template Function VC-14; March 18, 2014
- CAP 1422600; (a)(1) Determination for D1 and D2 Emergency Diesel Generator; March 14, 2014
- CAP 1429635; MRule (a)(3): (a)(1) Action Plan Work Orders and AR extended; May 6, 2014
- H2; Boric Acid Corrosion Control Program; Revision 24
- PINGP – System Health Report for VC Chemical & Volume Control; January 14, 2014
- PINGP 1507, Boric Acid Corrosion Control VC-369-10 Leak Inspection; February 19, 2014
- Radiation Monitoring Maintenance Rule Scoping; September 10, 2013

- SP 1201D; Charging, Letdown & Seal Water Leakage Test; Revision 19

1R13 Maintenance Risk Assessment and Emergent Work

- FP-E-MR-09; Maintenance Rule (a)(4) Fire Risk Assessment Risk Management Actions; Revision 1
- H24.1; Appendix A; Phase 1 Risk Assessment Preparation; Revision 8
- H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 19
- Risk Assessment for Work Week 1418; May 5, 2014

1R15 Operability Evaluations

- 1C20.7 AOP1; Failure of D1 or D2 Lube Oil Keep Warm System; Revision 7
- 1C20.7; D1/D2 Diesel Generators; Revision 41
- 1E-0, Attachment L; Safety Injection Alignment Verification; Revision 32
- C1.1.20.7-13; D6 Diesel Generator Valve Status; June 9, 2011
- C1.1.20.7-14; D6 Diesel Generator Auxiliaries and Local Panels and Switches; Revision 12
- CAP 1425701; SG ULS Flange Bold Torque Issues; April 2014
- CAP 1426059; ULS Snubber Bracket Torque Equipment Calibration not Provided; June 13, 2014
- CAP 1427907; Instrument Air Control Valve Limit Switches Non-Conforming with Regulatory Guide 1.97; April 22, 2014
- FP-OP-COO-19; Log-keeping; Revision 1
- Operator Logs 3/31/14 and 4/1/14
- OPR 1414460-01; Steam Generator Water Level – Narrow Range Instruments; no date
- PM 3700-10-6; Calibration of Hytorc Sweeny Hydraulic Wrenches; May 20, 2014
- SP 1002A; Analog Protection System Calibration; August 14, 2012
- SP 2002A; Analog Protection System Calibration; Revision 36
- Technical Specification Bases for Section 3.6.3 – Containment Isolation Valves; Revision 200
- WO 433036-01; SP 1002A, Analog Protection System Calibration; August 17, 2012
- WO 449888-01; SP 2002A, Analog Protection System Calibration; April 16, 2013
- XH-28-44; Emergency Diesel Generator Set; Revision 0

1R18 Plant Modifications

- CAP 1428983; D1/D2 Components Missed in OPR 1327157; April 30, 2014
- CAP 1432831; EC 19815 and 19915 did not Contain a Complete Evaluation; May 29, 2014
- CAP 1433282; OPR 1202820-01 did not Consider D1/D2 Fan Pitch Positioner; June 3, 2014
- CAP 1433324; D1/D2 Room Supply and Exhaust Fan Pitch Positioners Bypass; June 4, 2014
- CAP 1433346; Track OBN for D1/D2 Vent Positioners; June 4, 2014
- CAP 1433400; Eighteen Additional Components Required to be Evaluated for D1/D2; June 4, 2014

1R19 Post Maintenance Testing

- 2C20.7; D5/D6 Diesel Generators; Revision 39
- CAP 1422360; 2CC-281-16 Swagelock Fitting Leaking; May 12, 2014
- CAP 1429517; Fuel Oil Leak on 2EG-21-1 not being Repaired; May 5, 2014
- CAP 1429530; Could Not Perform SP 2355A as Scheduled, Procedure Issue; May 6,2014
- CAP 1429633; MRule (a)(3): (a)(1) Process Does Not Stand Alone; May 6, 2014
- CAP 1431205; BACC: 21 RCP Pump Boric Acid Leak, Equipment 245-051; May 19, 2014

- CAP 17431207; Prefab Weld for 21 RCP Spare Spool Piece; May 19, 2014
- SP 1229B; Effluent Radiation Monitoring Quarterly Functional Test Train B; Revision 7
- SP 2295: D5 Diesel Generator 6-Month Fast Start Test; February 28, 2014
- WO 408202-03; 13 FCU CLG WTR INLT and BKR 112E-5; April 17, 2014
- WO 450554-01; 2R-22 Shield Building Vent Gas Rad Meter Power Supply Replacement; April 25, 2014
- WO 486408-01; SP 2307 – D6 Diesel Generator Six Month Fast Start; April 26, 2014
- WO 486441-01; Unit 0 Radiation Monitoring System; April 18, 2014
- WO 501424-12; OPS: PMT 21 RCP #3 Seal Leakoff Jumper Spool Piece; May 19, 2014
- WO 502526-02; OPS: PMT Flanged Connections; May 21, 2014

1R20 Refueling and Outage

- 2C1.2-M1; Unit 2 Startup To Mode 1; May 22, 2014
- 2C1.2-M2; Unit 2 Startup to Mode 2; Revision 1
- 2C1.3-M2; Unit 2 Shutdown to Mode 2; Revision 2
- 2C1.3-M3; Unit 2 Shutdown to Mode 3; Revision 2
- 2C1.4; Unit 2 Power Operation; Revision 53
- 2C1.4; Unite 2 Power Operation; Revision 53
- C1B; Appendix – Reactor Startup; Revision 20
- CAP 1427327; Boric Acid Corrosion Control Program Engineer to Evaluate Boric Acid Leak in Unit 2 Containment; April 17, 2014
- CAP 1427328; Leak Identified in Unit 2 Containment 21 Vault; April 17, 2014
- CAP 1431146; Limit of Personnel in Containment When Not In Mode 5; May 16, 2014
- CAP 1431172; 23 Heater Drain Tank Locked Out during Unit 2 Shutdown; May 18, 2014
- CAP 1431173; Unable to Move Unit 2 Control Rods Out Manually; May 18, 2014
- CAP 1431175; OPC Cycled After Taking Unit 2 Off the Grid; May 18, 2014
- CAP 1431213; Maintenance Outage Comment: Challenges with Outage Control Center Turnover; May 19, 2014
- CAP 1431218; 21 Reactor Coolant Pump Shaft Seal Return Temperature not less than 115 Degrees F per Procedure C3; May 19, 2014
- CAP 1431263; Active Boric Acid Leak on 2RC-8-19 Swagelock Cap; May 19, 2014
- CAP 1431285; 23 Fan Coil Unit Lower Northeast Face Corner Gasket Leaking; May 19, 2014
- CAP 1431287; Leak Identified on 23 Fan Coil Unit; May 19, 2014
- CAP 1431287; Leak Identified on 23 Fan Coil Unit; May 19, 2014
- CAP 1431342; 21 Reactor Coolant Pump Boric Acid Leak; May 19, 2014
- CAP 1431367; 23 Fan Coil Unit Leaking on Piping Flange at Southwest Corner; May 19, 2014
- CAP 1431401; 23 Fan Coil Unit Northeast Lower Inlet Flange Spacer Improperly Installed; May 20, 2014
- CAP 1431431; Action Request not Written when Puddle Near 23 Fan Coil Unit Initially Identified; May 20, 2014
- CAP 1431729; Failure to Document 23 Fan Coil Unit Leak in a Timely Manner; May 21, 2014
- CAP 1431900; Extent of Condition for Rod Control System Relay Sockets; May 22, 2014
- CAP 1431952; U2 Left Stop Valve (SV-1) Did Not Open On Turbine Latch; May 23, 2014
- CAP 1432070; Undervoltage Relay for Bus 12 Found Out of Tolerance; May 23, 2014
- D107; Containment Foreign Material Exclusion Control; Revision 8
- Engineering Change 24106; D107 Evaluation – Equipment Staged in Containment for 2F2801; Revision 0
- H56; GSI-191 Debris Monitoring Program; Revision 5
- Operational Decision Making Document for CAP 1427328; 21 Reactor Coolant Pump Seal Leakage into Containment; Revision 0

- Support/Refute Matrix for CAP 1427328 – Leak Identified in Unit 2 Containment 21 Vault; no date provided
- USAR Section 6.3.2.4; Cooling Water for the Fan Coil Units; Revision 32
- WO 103604; 23 FCU Lower Northeast Face Corner Gasket Leaking; May 21, 2014

1R22 Surveillance Test

- CAP 1425831; 1NU-51A NFM Drawer Retention Screws Loose; April 8, 2014
- CAP 1430484; IST Stoke Time Acceptance Criteria Incorrectly Revised; May 13, 2014
- CAP 1430834; SI Pump Recirculation Flowmeter ECR 7262 Not Progressing; May 15, 2014
- SP 1130A; Train A Containment Vacuum Breakers Quarterly Tests; Revision 12
- SP 1218; Monthly 4Kv Bus 15 Undervoltage Relay Test; May 13, 2014
- SP 1342; Neutron Flux Monitor Alignment at Reactor Power; April 8, 2014
- WO 487120-01; SP 2088A Train A Safety Injection Quarterly Test; May 9, 2014

2RS3 In-Plant Airborne Radioactivity Control and Mitigation

- 1C19.2 Containment System Ventilation Unit 1; Revision 26
- 2C19.2 Containment System Ventilation Unit 2; Revision 27
- 5AWI 10.1.2; Respirator Qualification Program; Revision 05
- B34; Instrument and Station Air; Revision 09
- C40.5; Control Room Breathing Air System; Revision 02
- D14; Chemical Handling; Revision 36
- H 26; Respiratory Protection Program; Revision 09
- MSA PosiChek3 Test Results; Selected Records; various dates 2013 and 2014
- NOS Observation Report 2013-01-013; Radiation Protection; February 28, 2013
- PING 1027; Breathing Air System Air Quality Tests; Selected Records; various dates 2013 and 2014
- PING 1028; PSI Visual Cylinder Inspection Evaluations; Selected Records; various dates 2013 and 2014
- Respiratory Protection Equipment NIOSH Certifications; Selected Records; various dates 2014
- Respiratory Protection Qualification Records; Selected Records; various dates 2013 and 2014
- RPIP 1210; Charging SCBA Air Cylinders; Revision 13
- RPIP-1204; Evaluation of Airborne Radioactivity; Revision 18
- RPIP-1214; Respiratory Protection Equipment Testing; Revision 18
- RPIP-1215; Respiratory Equipment Control; Revision 07
- RPIP-1216; Max Air 2000-800 Respiratory Protection; Revision 00
- RPIP-1219; Respirator Use; Revision 19
- RPIP-1226; Control Room Breathing Air System Testing; Revision 04
- Scott PosiChek3 Test Results; Selected Records; various dates 2013
- SWI O-43; Operator Qualification Program; Revision 14
- TP-1514; Quarterly Emergency Plan Equipment Test; Revision 29

2RS4 Occupational Dose Assessment

- Declared Pregnant Worker Documentation; Selected Records; dated 2013
- FG-RP-BSR-01; Bioassay Sample Report; Revision 01
- FP-RP-AM-01; Alpha Monitoring Program; Revision 03
- FP-RP-BP-01; Bioassay Program; Revision 06
- FP-RP-DP-01; Dosimetry Program; Revision 06

- FP-RP-SD-01; Special Dosimetry; Revision 09
- FP-RP-WBC-01; Whole Body Counter Use and Functional Check; Revision 03
- NVLAP Scope of Accreditation; Effective Dates July 2013 through June 2014
- Personnel Contamination Logs; dated 2013 and 2014
- Positive Whole Body Count Documentation; Selected Records, dated 2013 and 2014
- Radiation Occurrence Reports; Selected Records; various dates 2013 and 2014
- RPIP 1101; TLD Issue; Revision 23
- RPIP 1107; Fetal Protection Program; Revision 10
- RPIP 1123; Alpha Characterization Smears; Revision 1
- RPIP 1126; Contamination Monitor Alarm Response and Personnel Decontamination; Revision 24

4OA1 Performance Indicator Verification

- Control Room Narrative Logs; various dates
- GAR 1382087-01; MSPI Data for Residual Heat Removal (RHR) and Safety Injection (SI) Systems; April 2013
- GAR 1382090; MSPI Data for RHR and SI Systems; May 2013
- GAR 1382091; MSPI Data for RHR and SI Systems; June 2013
- GAR 1382092; MSPI Data for RHR and SI Systems; July 2013
- GAR 1395404; MSPI Data for RHR and SI Systems; August 2013
- GAR 1399385; MSPI Data for RHR and SI Systems; September 2013
- GAR 1404751; MSPI Data for RHR and SI Systems; October 2013
- GAR 1408389; MSPI Data for RHR and SI Systems; November 2013
- GAR 1413376; MSPI Data for RHR and SI Systems; December 2013
- GAR 1417462; MSPI Data for RHR and SI Systems; January 2014
- GAR 1418623; MSPI Data for RHR and SI Systems; February 2014
- GAR 1421924; MSPI Data for RHR and SI Systems; March 2014
- MSPI Derivation Reports – Units 1 and 2 Heat Removal Systems; April 2013 – March 2014
- MSPI Derivation Reports – Units 1 and 2 High Pressure Safety Injection Systems; April 2013 – March 2014

4OA2 Identification and Resolution of Problems

- Abnormal Procedure AB-4; Flood; Revision 41
- Calculation ENG-ME-529; Flood Barrier Leakage Criteria; Revision 0
- CAP 1357039; 2102 Fukushima Flooding Walkdowns – AB-4 Suggestions; October 30, 2012
- CAP 1392174; Install and Remove Flood Panel MK-1 East Auxiliary Building; August 1, 2013
- CAP 1395149; Pull Box Conduit not Sealed; August 29, 2013
- CAP 1395969; 121 Heating Boiler Fuel Oil Storage Tank Pump Stopped during Transfer; October 7, 2013
- CAP 1397510; Flooding Bulkhead Installation Lacks Documented Timing Study; September 19, 2013
- CAP 1397532; NOS Adverse Assessment Finding – Prairie Island Flood Preparation Inadequate; September 19, 2013
- CAP 1397744; Flood Protection WO not Completed after Two Years; September 20, 2013
- CAP 1400888; SP 2100 not done in 2R28, how will October Only Items Get Done; October 10, 2013
- CAP 1401947; Unsealed Pull Boxes; October 16, 2013
- CAP 1417079; Question About Possible Pre-Conditioning During SP 1106B; January 31, 2014
- CAP 1417083; Question About Possible Pre-Conditioning During SP 1106B; January 31, 2014

- CAP 1417111; During SP 1106B A Question On Dedicated Operator Occurred; January 31, 2014
- CAP 1417161; Unplanned LCO Entry Due To Failure Of 22 DD Cooling Water Pump; February 1, 2014
- CAP 1421516; 122 Heating Boiler Oil Storage Tank Pump Didn’t Stay Running during Performance of Test Procedure; March 6, 2014
- CAP 1421608; Could both Heating Boiler Oil Storage Tank Pumps Out of Service be an Unanalyzed Condition; March 6, 2014
- CAP 1423761; Flood Door Installation Testing Lessons Learned (Door 102); March 21, 2014
- CAP 1423767; Flood Door Installation Testing Lessons Learned (Door 104); March 21, 2014
- CAP 1424210; Flood Door Installation Testing Lessons Learned (Door 73); March 26, 2014
- CAP 1424211; NRC Identified Issue on Door 44 Flap; March 26, 2014
- CAP 1424623; Flood Panel Timing Lessons Learned Issues (Door 45); March 28, 2014
- CAP 1424803; Flood Panel Timing Lessons Learned Issues (Door 46); March 31, 2014
- CAP 1425068; Flood Panel Timing Lessons Learned Issues (Door 44); April 2, 2014
- CAP 1425071; Flood Panel Timing Lessons Learned Issues (Door 47); April 2, 2014
- CAP 1425346; Flood Panel Timing Lessons Learned Issues (Door 437); April 3, 2014
- CAP 1430125; SP 2100 Quarterly Requirements for 4Q13 not Credited Properly; May 9, 2014
- Drawing NF-173000; Flood Protection Key Plan and Details; Revision 76
- Drawing NH-172997-6; Auxiliary Building Flood Protection Key Plan and Details; Revision 77
- Drawing NH-172997-9; Turbine Building Flood Protection Key Plan and Details; Revision 0
- EC 21604; Remove Redundant External Flooding Barriers; Revision 0
- EC 23670; Time Validation Criteria for AB-4 Flood, Attachment J, Revision 41, Bulkhead Removal Installation Instructions; March 2, 2014
- GAP Analysis for CAP 1397532; September 2013
- Lesson Guide P8345A-1401; Bulkhead Installation Timing Study; all revisions
- Prairie Island Nuclear Generating Plant External Flooding Walkdown Report; November 2012
- Prairie Island Nuclear Generating Plant Flood Hazards Walkdown Report ; no date
- Root Cause Evaluation 1397532; NOS Adverse Assessment Finding – Prairie Island Flood Preparation Inadequate; Revision 2
- SP 1293; Annual Inspection of Flood Control Measures; February 5, 2014
- Special Test Procedure ST FB-INSTALL GP1; Flood Barrier Installation Timing Group 1 Doors; Revision 0
- WO 388201; SP 1293 - Annual Inspection of Flood Control Measures; February 2, 2010
- WO 477700; SP 2100 – 21 Motor Driven Auxiliary Feedwater Pump Monthly Test; December 4, 2013
- WO 479679; Perform AB-4 Testing on Doors; all revisions
- WO 488912; SP 2100 – 21 Motor Driven Auxiliary Feedwater Pump Monthly Test; December 9, 2013

4OA3 Event Followup and Notices of Enforcement Discretion

- Alarm Response Procedure C47023-0601; Substation Local Alarm; Revision 34
- Alarm Response Procedure C47024-0301; Bus 15 4.16 kV Degraded Voltage; Revision 35
- B20.5; 4.16 kV Station Auxiliary System; Revision 8
- Calculation ENG-EE-167; Evaluation of Offsite Power during Flood Conditions; no revision provided
- CAP 1396993; EDG Oil Supplies may not be Sufficient for Maximum Flooding; October 18, 2013
- CAP 1435709; Unit 2 Transient due to Isolating CV-31062 in Wrong Order; June 23, 2014
- CAP 1435793; 10 Bank Transformer Load Tap Changer not Functioning; June 23, 2014

- CAP 1435802; D1 DG Lockout on Reverse Power; June 23, 2014
- Clearance Order 58702; Isolate CV-31062; no date
- Control Room Narrative Logs; June 19 and 20, 2014
- Control Room Narrative Logs; June 23, 2014
- EC 23634; Evaluation of Fuel Oil Consumption for an External Flooding Event; February 26, 2014
- Procedure 1C20.5; 4.16 kV System; Revision 19
- Procedure 1C20.7; D1/D2 Diesel Generators; Revision 42
- Procedure FP-OP-OL-01; Conduct of Operations; Revision 13
- Procedure FP-OP-TAG-01; Fleet Tagging/ Revision 20
- SP 1032A; Safeguards Logic Testing
- Technical Specification 3.7.8; Cooling Water; no date
- Technical Specification 3.8.3; Diesel Fuel Oil; no date
- Updated Safety Analysis Report; Section 8
- USAR Section 8.4; 4.16 kV Electric System; Revision 33

4OA5 Other Activities

- CAP 1424460; NRC License Amendment Implementation Requirements not Met; March 27, 2014
- CAP 1425039; AST Amendment Gap Analysis; April 1, 2014

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
AST	Alternate Source Term
CAP	Corrective Action Program
CFR	Code of Federal Regulations
DDCLP	Diesel Driven Cooling Water Pump
DRP	Division of Reactor Projects
EC	Engineering Change
EDG	Emergency Diesel Generator
FCU	Fan Coil Unit
HBOST	Heating Boiler Oil Storage Tank
IMC	Inspection Manual Chapter
IP	Inspection Procedure
kV	Kilovolt
LER	Licensee Event Report
LERF	Large Early Release Frequency
MSPI	Mitigating Systems Performance Indicator
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-licensed Operator
NOS	Nuclear Oversight Department
NRC	U.S. Nuclear Regulatory Commission
OCC	Outage Control Center
PARS	Publicly Available Records System
PI	Performance Indicator
PWR	Pressurized-water Reactor
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
SCBA	Self-Contained Breathing Apparatus
SDP	Significance Determination Process
SGTR	Steam Generator Tube Rupture
SP	Surveillance Procedure
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
TDAFW	Turbine Driven Auxiliary Feedwater
TS	Technical Specification
TSO	Transmission System Operator
USAR	Updated Safety Analysis Report
WO	Work Order

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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

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Letter to Kevin Davison from Kenneth Riemer dated August 11, 2014.

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2014003;
05000306/202014003

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