UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

February 7, 2013

Mr. James E. Lynch
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 05000282/2012005; 05000306/2012005; AND 07200010/2012001

Dear Mr. Lynch:

On December 31, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on January 10, 2012, with you and other members of your staff.

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

Based on the results of this inspection, five NRC-identified findings of very low safety significance were identified. Four of the findings involved a violation of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, several licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of any NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant.

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

Sincerely,

/RA/

Kenneth Riemer, Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2012005; 05000306/2012005; and 07200010/2012001
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:	05000282/2012005; 05000306/2012005; and 07200010/2012001
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	October 1 through December 31, 2012
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector R. Baker, Operator Licensing Examiner K. Barclay, Resident Inspector – Kewaunee J. Beavers, Emergency Preparedness Inspector T. Bilik, Engineering Inspector M. Jones, Engineering Inspector J. Laughlin, Emergency Preparedness Inspector M. Learn, Independent Spent Fuel Storage Installation Inspector D. McNeil, Senior Operator Licensing Examiner C. Moore, Operator Licensing Examiner D. Oliver, Operator Licensing Examiner D. Passehl, Senior Reactor Analyst M. Phalen, Radiation Protection Inspector
Approved by:	Kenneth Riemer, Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000282/2012005, 05000306/2012005; 07200010/2012001, 10/01/2012 – 12/31/2012; Prairie Island Nuclear Generating Plant, Units 1 and 2; Inservice Inspection; Licensed Operator Requalification; Maintenance Effectiveness; Other Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. This inspection report also includes the results of an inspection on the Independent Spent Fuel Storage Installation. Five Green findings were identified by the inspectors. Four of these findings are considered non-cited violations (NCVs) of NRC regulations. The significance of inspection findings are indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspect are determined using IMC 0310, "Components Within the Cross Cutting Areas" dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated June 7, 2012. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance and a NCV of 10 CFR50.55a(g)(4) on November 13, 2012, due to the licensee's failure to disposition a relevant indication on a common steam generator snubber reservoir in accordance with the American Society of Mechanical Engineers (ASME) OM4 Code. Specifically, the licensee did not properly evaluate and disposition a condition where the hydraulic fluid level for a common reservoir serving snubbers H1 through H4 on the 12 steam generator was below the minimum required. The licensee issued a work order to fill the reservoir and documented the failure to properly disposition the indication in the corrective action program.

  The inspectors determined that this finding was more than minor because if left uncorrected, the failure to properly disposition relevant indications could become a more significant safety concern. Absent NRC identification of this issue, the licensee would not have re-established the required fluid level in the reservoir for an indefinite period. This finding was determined to be of very low safety significance because a subsequent evaluation demonstrated that the low fluid level did not result in the piping system becoming inoperable. This issue was determined to be cross cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee failed to thoroughly evaluate problems such that the resolutions addressed the cause and extent of condition, as necessary (P.1(c)). (Section 1R08.1)

- Green. The inspectors identified a finding of very low safety significance on October 6, 2012, due to the failure to properly evaluate an operating crew's annual requalification examination performance in accordance with Procedure FP-T-SAT-73, "Licensed Operator Requalification Program Examinations." Specifically, the evaluators did not adequately assess the communications competency area when evaluating the crew's overall performance. As a result, the crew's performance was rated as "satisfactory with remediation" rather than as "unsatisfactory." Corrective actions for this issue included providing remedial training to the crew and having the crew complete an additional evaluated scenario as part of their annual examination.

This issue was more than minor because if left uncorrected the failure to properly assess licensed operator performance had the potential to lead to a more significant safety concern. The inspectors determined that this issue could be evaluated using IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process." The inspectors determined that this finding was of very low safety significance because it was related to the licensee's administration of an annual requalification operating test as discussed in Section 03.05 of NRC Inspection Procedure 71111.11, "Licensed Operator Requalification Program." This issue was determined to be cross-cutting in the Human Performance, Decision Making area because the licensee did not make conservative assumptions during decisions regarding how this crew of licensed operators was evaluated (H.1(b)). (Section 1R11.3)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," due to the licensee's failure to implement vendor recommendations to replace rubber hoses on the emergency diesel generators (EDGs) at a 10-year frequency. Specifically, some of the installed rubber hoses were found to be in service beyond the vendor recommended service life and if they were to degrade, could impact the safety-related functions of the EDGs. Corrective actions for this issue evaluating the condition and replacing the hoses on specific diesel engines.

  The inspectors determined that this issue was more than minor because if left uncorrected, it could become a more significant safety concern because the rubber hoses could continue to degrade until operation of the diesel engines were impacted. The finding was of very low safety significance because each of the questions listed in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," could be answered "no." Due to the age of this issue, the cause of the finding was not reflective of current performance and therefore, a cross cutting aspect was not assigned. (Section 1R12.1)

- Green. The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, on June 26, 2012, due to the licensee's failure to have procedures appropriate to the circumstance for coordinating and preparing for the onset of hot weather conditions. Specifically, Procedure FP-WM-SR-01, "Seasonal Readiness Program," Attachment 2, failed to include criteria to ensure that issues associated with the ability of the Unit 1 EDGs to operate when outside air temperatures exceeded 97 degrees Fahrenheit were identified and addressed prior to the onset of hot weather. This resulted in both Unit 1 EDGs being rendered inoperable, and the D1 EDG being rendered unavailable, on July 2, 2012.

  The inspectors determined that this issue was more than minor as it impacted the protection against external events objective of the Mitigating Systems Cornerstone. In addition, this finding impacted the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this issue was of very low safety significance because each of the questions listed in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems

Screening Questions," could be answered "no." This finding was cross cutting in the Human Performance, Work Control area because Procedure FP-WM-SR-01 was not written to ensure that activities needed to support long term equipment reliability and availability were planned such that they were performed in a preventative manner rather than in a reactive manner (H.3(b)). (Section 4OA5.2)

- Green. A finding of very low safety significance and an NCV of 10 CFR 50.65 was identified by the inspectors on August 22, 2012, due to the licensee's failure to demonstrate that the performance or condition of the radiation monitoring system was being effectively controlled through the performance of appropriate preventive maintenance such that the structure, system or component (SSC) remained capable of performing its intended function. Specifically, the licensee failed to perform maintenance rule evaluations following the failure of multiple radiation monitors in July 2010. Since the evaluations were not completed, the licensee was unable to demonstrate that the performance of the radiation monitors was being effectively controlled through the performance of maintenance. Corrective actions for this issue included performing the evaluations and comparing the results to pre-established performance monitoring criteria.

  The inspectors determined that this finding was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone and impacted the cornerstone's objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. This finding also impacted the SSC and barrier performance attributes of the Barrier Integrity Cornerstone by affecting the reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents and events. The inspectors determined that this issue was of very low safety significance because each of the questions listed in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," could be answered "no." The inspectors determined that this finding was cross cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee failed to thoroughly evaluate this problem such that the resolution addressed the cause and extent of condition as necessary (P.1(c)). (Section 4OA5.3)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at full power. On October 23, 2012, operations personnel shut down the Unit 1 reactor to begin Refueling Outage 1R28. Major items completed during the refueling outage included maintenance on the emergency diesel generators (EDGs), heat exchanger testing, repair of two cooling water lines, multiple valve replacements, and the completion of many license renewal activities in preparation for entering the period of extended operation. Unit 1 was taken critical on the evening of December 31, 2012. The Unit 1 reactor was operating at approximately two percent power at the conclusion of the inspection period.

Unit 2 operated at or near full power the entire inspection period. Operations personnel performed short duration power reductions to allow for routine testing of plant equipment.

On October 31, 2012, the licensee declared a Notice of Unusual Event (NOUE) due to a security related issue. The inspectors were onsite at the time of the event. The inspectors monitored the licensee's response from the control room and specific security posts. The NOUE was terminated 3.5 hours later.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 12 Diesel Driven Cooling Water Pump;
- Walkdowns of the screenhouse basement and Procedure AB-4, "Flooding," performed as part of Temporary Instruction (TI) 2515/187, "Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns"; and
- Walkdowns of the Unit 2 Auxiliary Feedwater Pumps, Bus 16 Switchgear, and Spent Fuel Pumps performed as part of TI 2515/188, "Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns".

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

These activities constituted five partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04-05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On November 28, 2012, the inspectors performed a complete system alignment inspection on the accessible portions of the Unit 2 auxiliary feedwater system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Unit 2 side of the screenhouse basement;
- Bus 111, 112 and 121 Switchgear Rooms;
- Bus 25, 26 and 27 Switchgear Rooms;
- Train A Event Monitoring Room and Unit 2 Turbine Building Ground/Mezzanine Elevations; and
- Unit 2 Auxiliary Building Mezzanine Level.

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 (OOS), degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.

The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the licensee's Individual Plant Examination of External Events (IPEEE) 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.

1R08 Inservice Inspection Activities (71111.08P)

From October 29 through November 16, 2012, the inspectors reviewed the licensee's Inservice Inspection (ISI) Program. The licensee used this program for monitoring degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, risk significant piping and components, and containment systems.

The inspections described below constituted one inservice inspection sample as defined in IP 71111.08.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors observed the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements. If any indications or defects were detected, the inspectors reviewed the licensee's actions to determine whether the items were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Risk-informed, ultrasonic examinations of the following “A” train safety injection Class II welds:

  - Pump discharge 3 inch reducer-to-pipe weld (W-2);
  - Pump discharge 3 inch pipe-to-elbow weld (W-3);
  - Pump discharge 3 inch elbow-to-45 elbow weld (W-4); and
  - Pump discharge 3 inch elbow-to-pipe weld (W-5).

- Dye penetrant examination (PT) of the residual heat removal (RHR) system, Loop “A,” Class 1 integrated attachment welds for H-3/1A on the 8-RC-15A line; and

- Visual examinations (VT) on the following components:

  - VT-1 of 4 orifice bolts (B-2) on the Class 1 seal injection loop “A” line;
  - VT-3 of spring hanger (H-3) for the Class 1 seal injection loop “A” line;
  - VT-3 of restraint/clamp (H-3) for the Class 1 seal injection loop “A” line; and
  - VT-3 of rod/clamp (H-6) for the Class 1 seal injection loop “A” line.

The inspectors reviewed the dispositioning of previously identified relevant/recordable indications identified during the previous refueling outage to ensure that those indications accepted for continued service were evaluated in accordance with the ASME Section XI Code or an NRC approved alternative.

- Indication (PT) Disposition of Integral Attachment (Rigid Restraint/2 lugs), H-2/IA;
- Indication (PT) Disposition of Integral Attachment of Pipe Support 1-RCVCH-922; and
- Indication (PT) Disposition of Integral Attachment of Pipe Support 1-RCVCH-896.

The inspectors reviewed the following pressure boundary welds completed for risk significant systems since the beginning of the last refuelling outage to determine if the licensee applied the pre-service, non-destructive examinations and acceptance criteria required by the Construction Code and ASME Code, Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of the Construction Code and the ASME Code Section IX.

- Weld repair/replacement of Class 2, 12 steam generator blow down isolation train A motor valve (valve MV-32043);
- Weld repair/replacement of Class 1 pipe support integral attachment for a volume control system line (pipe support 1-RCVCH-896); and
- Installation of high point vent valve (CS-33-5) for void location (1CS-09) in Class 2 containment spray line 2-CS-4.

b. <u>Findings</u>

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

No exams were required this outage. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors performed an independent walkdown of the reactor coolant system and related lines in the containment including the under vessel penetrations, which had received a recent licensee boric acid walkdown and verified whether the licensee's boric acid corrosion control (BACC) visual examinations emphasized locations where boric acid leaks can cause degradation of safety significant components.

The inspectors reviewed the following licensee evaluations of reactor coolant system components with boric acid deposits to determine if degraded components were documented in the corrective action system. The inspectors also evaluated corrective actions for any degraded reactor coolant system components to determine if they met the ASME Section XI Code.

- Condition Evaluation (CE) 1284031; Boric Acid (BA) Indication Evaluation on CV-31325 2" Chemical, Volume and Control System Valve;
- CE 1284002; Body-to-Bonnet Gasket Leak, BA Indication on the MV-32083 Fasteners; Supply to Safety Injection Pump Isolation;
- CE 1197934; BA Indication Evaluation on MV-32231, Reactor Coolant System Loop B; and
- CE 1356914; RH-2-6, Residual Heat Removal Heat Exchanger Outlet Crosstie, Body-to-Bonnet BA Indication Evaluation.

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- CAP 1312553; Corrosion Evaluation Required for MV-32074;
- CAP 1285037; ASME Relevant Boric Acid Leakage on RH-2-6;
- CAP 1284031; ASME XI Relevant Boric Acid Flange Leak on CV-31325; and
- CAP 1299806; Boric Acid Fitting Leak above RC-8-32.

b. Findings

No findings were identified.

.4 Steam Generator Tube Inspection Activities

a. Inspection Scope

The NRC inspectors observed acquisition of eddy current (ET) data, interviewed ET data analysts, and reviewed documentation related to the steam generator (SG) ISI program to determine if:

- In-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute (EPRI) TR-107620, Steam Generator In-Situ Pressure Test Guidelines and that these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;

- the numbers and sizes of SG tube flaws/degradation identified was bound by the licensee's previous outage Operational Assessment predictions;

- the SG tube ET examination scope and expansion criteria were sufficient to meet the Technical Specifications, and the EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6;

- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;

- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;

- the licensee implemented repair methods which were consistent with the repair processes allowed in the plant TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;

- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);

- the licensee's primary-to-secondary leakage (e.g., SG tube leakage) was below 3 gallons-per-day or the detection threshold during the previous operating cycle;

- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current Examination, of EPRI 1003138, Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 6; and

- the licensee performed secondary side SG inspections for location and removal of foreign materials.

The licensee did not perform in-situ pressure testing of SG tubes. Therefore, no NRC review was completed for this inspection attribute.

b. Findings

No findings were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if the licensee had:

- established an appropriate threshold for identifying ISI/SG related problems;
- performed a root cause (if applicable) and taken appropriate corrective actions; and
- evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. Documents reviewed are listed in the Attachment to this report.

b. Findings

Introduction: A finding of very low safety significance and associated Non-Cited Violation (NCV) of 10 CFR 50.55a(g)(4), was identified by the inspectors for the licensee's failure to disposition a relevant indication related to four steam generator snubbers in accordance with the ASME OM4 Code.

Description: While reviewing CAP 1285744, the inspectors identified that the licensee had failed to take appropriate action to disposition a relevant indication. An ISI examination of steam generator snubbers H-1 through H-4 performed on May 7, 2011, revealed that the snubbers' common reservoir was less than half full. At this level, the reservoir was below the specified amount sufficient for snubber actuation at its operating extension. In addition, this level was not sufficient to satisfy the ASME Code provisions for hydraulic snubbers. The ASME OM Code detailed a variety of methods that could be used to disposition the indication. These methods included testing, evaluation, adjusting, repairing, modifying, or replacing. However, the licensee failed to disposition the indication in accordance with any of the Code permitted alternatives, and instead, elected to return the reservoir to service. Information provided in CAP 1285744 stated that the snubber reservoir had sufficient fluid for makeup. The inspectors determined that this justification lacked verifiable technical rational (evaluation) and therefore, was contrary to the ASME OM Code requirements. The licensee generated CAP 1359101 to document the inspectors concern, address the ASME Code non-conformance, and to evaluate operability. The licensee also generated WO 450902 to fill the reservoir to the required level.

Analysis: The inspectors determined that a failure to perform a test, evaluate, adjust, repair, modify, or replace the relevant condition on a steam generator snubber reservoir was contrary to ASME OM4, and was a performance deficiency.

The finding was determined to be more than minor because if left uncorrected the finding would become a more significant safety concern. Specifically, the improper disposition of the indication resulted in the licensee failing to assure that the specified amount of snubber fluid was sufficient for snubber actuation at its operating extension. In addition, the licensee failed to address why the as-found reservoir condition satisfied the ASME Code provisions for hydraulic snubbers.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, Attachment 0609.04, "Initial Characterization of Findings." Because the licensee subsequently completed an evaluation that demonstrated the structural integrity of the piping system, the inspectors answered "Yes" to the IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions." Specifically, the inspectors answered "Yes" to the question "If the finding is a deficiency affecting the design or qualification of a mitigating structure, system or component (SSC), does the SSC maintain its operability or functionality?" Therefore, this finding screened as having very low safety significance (Green). The inspectors determined that this finding had a cross cutting aspect in the Problem Identification and Resolution, CAP area because the licensee failed to thoroughly evaluate problems such that the resolutions addressed the cause and extent of condition, as necessary (P.1(c)).

Enforcement: Title 10 CFR 50.55a(g)(4), states in part that "Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, components (including supports) which are classified as ASME Code Class 1, Class 2, and Class 3 must meet the requirements set forth in Section XI of editions and addenda of the ASME Boiler and Pressure Vessel Code (or ASME OM Code for snubber examination and testing)."

ASME Section XI, 1998 Edition w/2000 Addenda, IWF-5300 Inservice Examinations and Tests, states that "Inservice examinations shall be performed in accordance with ASME/ANSI OM, Part 4, using the VT-3 visual examination method described in IWA-2213."

The ASME OM4 Code – 1998, 2000 Addenda, Section ISTD-4200, "Inservice Inspection," states that "Snubbers shall be visually examined on the required schedule and evaluated to determine their operational readiness."

Section ISTD-4233, "Design-Specific Characteristics," states in part that, "If the fluid is less than the minimum amount, the installation shall be identified as unacceptable, unless a test established that the performance of the snubber is within specified limits."

Section ISTD-4270, "Inservice Examination Failure Evaluation," states that "Snubbers that do not meet examination requirements of ISTD-4230 shall be evaluated to determine the root cause of the unacceptability."

Section ISTD-4280, "Inservice Examination Corrective Action," states that "Unacceptable snubbers shall be adjusted, repaired, modified, or replaced."

In addition, Xcel Energy Visual Examination, VT-3 Procedure, FP-PE-NDE-530, Revision 6, Paragraph 5.7.8, states in part that "For hydraulic shock suppressors (snubbers) the examination SHALL also include the detection of the following,……..(3) Verify that fluid level is at least a minimum of ½ full ….."

Paragraph 5.8.1 states in part that, “A component support whose visual examination detects relevant indications shall be reported as unacceptable. These conditions include (4) Fluid loss beyond specified limits…..”

Paragraph 5.8.6 states in part that “The NDE Level III is responsible for ensuring the required evaluations are completed”…Item 5 of this paragraph states “Refer to OM Code, ISTD-4230 for Snubber Examination Acceptance Standards.”

Lastly, Paragraph 5.8.7 states that, “It is the responsibility of a Level II or III to review and disposition indications in accordance with the applicable acceptance standards.”

Contrary to the above, on May 5, 2011, the licensee failed to correctly disposition a recordable indication on a common reservoir which served four snubbers on the 12 SG. Specifically, the licensee failed to correct a low reservoir level indication by testing, evaluating, adjusting, repairing, modifying, or replacing, as required by the ASME OM-4 Code. Because this violation was of very low safety significance and it was entered into the licensee’s CAP as CAP 1359101, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2012005-01: Failure to Disposition a Relevant Snubber Indication in Accordance with ASME Code)**.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Annual Operating Test, administered by the licensee from September 17 through October 26, 2012, required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, “Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee’s program to meet the requirements of 10 CFR 55.59.

This inspection constituted one licensed operator requalification annual operating test results inspection sample as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.2 Conformance with Examination Security Requirements (10 CFR 55.49)

a. Inspection Scope

The inspectors conducted an assessment of the licensee’s processes related to examination integrity (e.g., control of licensed operators during operating tests) to verify compliance with 10 CFR 55.49, “Integrity of Examinations and Tests.” The inspectors reviewed the facility licensee’s examination security error and compared it to NRC requirements.

This inspection was completed as part of the annual licensed operator requalification sample discussed above and was not counted as an additional inspection sample.

b. Findings

At the start of administration of a simulator operating test scenario, the simulator setup checklist was inadvertently left on the simulator floor. The simulator setup checklist was found by an operator who immediately notified the examination team. The evaluation team informed Training Supervision. The evaluation team also replaced the test scenario even though there was no opportunity for examination compromise. No performance deficiency or violation of NRC requirements was identified since the examination was not compromised,

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

a. Inspection Scope

On October 2, 2012, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was 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 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. This inspection also satisfied the requirement for the resident inspectors to observe a portion of the annual requalification operating test since the biennial portion of this IP was not performed in 2012.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) for the failure to properly evaluate the crew's performance in accordance with Procedure FP-T-SAT-73, "Licensed Operator Requalification Program Examinations." Specifically, the evaluators did not adequately assess the communications competency area when evaluating the crew's overall performance. As a result, the evaluators assessed the crew's performance as "satisfactory with remediation" rather than as "unsatisfactory."

Description: While observing a crew of licensed operators in the simulator, the inspectors and evaluators noted that the crew satisfactorily performed all critical tasks associated with the scenario. However, the inspectors and the evaluators identified the following:

- A senior reactor operator (SRO) informed the crew regarding the presence of a "first out" alarm due to exceeding the flux rate reactor trip setpoint. However, none of the licensed operators communicated that an anticipated transient without scram (ATWS) condition had occurred. The operator at the controls manually tripped the reactor and informed the crew that the reactor was tripped. However, this individual failed to communicate that the reactor had not automatically tripped as required and that the reactor trip was accomplished by manually actuating the reactor trip system. As a result, the crew (three SROs and two reactor operators) failed to declare an ALERT in accordance with Emergency Action Level (EAL) SA2.1 during the examination due to being inattentive when the information was provided on the simulator control room panels.

- Following a simulated high energy line break (HELB) in the auxiliary building, the crew failed to initially implement the requirements of Procedure F9, "High Energy Line Break/Leak (HELB)." Although one of the SROs referred to the procedure, no actions were taken. Approximately 20 minutes later, another SRO directed that Procedure F9 be implemented. The failure to implement Procedure F9 in a timely manner resulted in the crew failing to provide needed information to key personnel outside of the control room and delayed the simulated evacuation of the auxiliary building. Had this been an actual event, the delayed evacuation could have resulted in a significant impact to the plant due to personnel being injured by the high energy steam.

Following the scenario, the inspectors observed the licensee's evaluators assessing the crew's performance. The evaluators held multiple, lengthy discussions during the evaluation process regarding the two items above. The licensee's evaluation process consisted of rating the crew on several factors within six competency areas. Each factor was given a score between "1" (the lowest score) and "3" (the highest score). After rating each factor, the evaluators calculated an average of the rating factor scores. This average then became the overall score for the respective competency area. The evaluators used the competency area scores to determine an overall rating of satisfactory, satisfactory with remediation, or unsatisfactory. Following several discussions, the licensee's evaluators concluded that the crew would be assessed as "satisfactory with remediation."

The inspectors and four regional operator licensing examiners reviewed QF-1073-02, Revision 2, "Crew Operator Simulator Examination Summary," to assess how the licensee's evaluators assessed the operations crew in each competency area. The NRC personnel were concerned that the crew was not properly rated in the communications competency area. Specifically, two of the three factors within this area were rated as a "2" while the remaining factor was rated as a "1." The NRC inspectors and examiners agreed that factor (b), "Keep key personnel outside of the control room informed of plant status," was properly assessed as a "1" due to the delays in evacuating the auxiliary building following the HELB. However, NRC personnel disagreed with the "2" rating assessed in factor (c), "Ensure receipt of clear, easily understood communications from the crew and others." Due to the crew performance issues discussed above, the inspectors and examiners concluded that scoring rating factor (c) as a “1” was more reflective of the crew’s performance during the observed scenario due to the crew being inattentive to the ATWS condition.

Step 5.6.5.3b of FP-T-SAT-73 required that the crew be assessed as failing the evaluation (or unsatisfactory) if any two rating factors within any competency area received a score of “1.” Contrary to the above, the crew was not assessed as failing the evaluation (or being rated as unsatisfactory) due to the licensee’s evaluators improperly assessing the rating factors within the communications competency area.

Analysis: The inspectors determined that the failure to adhere to Step 5.6.5.3b of Procedure FP-T-SAT-73 was a performance deficiency that required an evaluation using the SDP. This issue was determined to be more than minor because if left uncorrected the failure to properly assess licensed operator performance had the potential to lead to a more significant safety concern. The inspectors determined that this issue could be evaluated using the SDP in accordance with IMC 0609, Attachment 0609.04, “Initial Characterization of Findings.” The inspectors used IMC 0609, Appendix I, “Licensed Operator Requalification Significance Determination Process,” and determined that this finding was of very low safety significance (Green) because it was related to the licensee’s administration of an annual requalification operating test as discussed in Section 03.05 of NRC Inspection Procedure 71111.11, “Licensed Operator Requalification Program,” **(FIN 05000282/2012005-02; 05000306/2012005-02: Inadequate Evaluation of Operating Crew during Annual Requalification Examination)**.

This issue was determined to be cross-cutting in the Human Performance, Decision Making area because the licensee did not make conservative assumptions during decisions regarding how this crew of licensed operators was evaluated (H.1(b)). The licensee initiated CAP 1362132 in response to this issue. Corrective actions for this issue included providing remedial training to the crew, having the crew complete an additional evaluated scenario, and discussing this issue with the operations training staff.

Enforcement: No violation of NRC requirements was identified since the structure and implementation of the licensee’s operator requalification evaluation process was not covered by current NRC regulations.

.4 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On October 22, 2012, the inspectors observed licensed operators during the performance of a Unit 1 shutdown for refueling outage 1R28. 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 alarms;
- correct use and implementation of procedures;
- control board manipulations;

- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions.

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

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

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- 480 Volt Breakers and
- Diesel Generators/Engines

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 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

Introduction: A finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to implement vendor recommendations to replace rubber hoses on the diesel generators at a 10-year frequency.

Description: License Renewal (LR) Commitment 43, "Replace DG Rubber Hoses," was created to ensure procedures are in place to require the periodic replacement of rubber hoses in contact with fuel oil and lube oil environments. On March 13, 2012, the licensee generated CAP 1329042 to document that the implementation tasks for this commitment were overdue. The licensee performed a condition evaluation to identify the hoses and affected systems captured in the scope of the LR Commitment. The licensee determined the D1 and D2 EDGs, D5 and D6 EDGs, the diesel driven cooling water pump (DDCLP) engines, and the diesel driven fire pump (DDFP) engine were included in scope for this commitment and closed the condition evaluation on April 13, 2012.

On November 2, 2012, the licensee changed the status of CAP 1329042 to complete after separate corrective actions were implemented for each in-scope system affected. For the D1/D2 EDGs, the licensee issued Preventive Maintenance Change Requests (PMCRs) after identifying the vendor recommended a 10-year replacement frequency. After applying a 25 percent grace period, the license established a 12-year replacement frequency, with the first opportunity for replacement being in the 1R29 refueling outage. For the DDCLP engines, the licensee utilized vendor input and operating experience to apply a 10-year replacement frequency. Similar to the D1/D2 EDG, the licensee determined that the first opportunity to replace hoses on the DDCLP engines would be during the 1R29 refueling outage. For the DDFP engine, the licensee issued a procedure change request to replace all hoses at a 10-year frequency instead of replacing the hoses "as required" as was stated in the previous preventive maintenance (PM) activity. The licensee determined the first opportunity to replace DDFP hoses would be in 2017 based on guidance in the PM procedure and the historical performance of DDFP hoses. For the D5/D6 EDGs, the licensee had implemented PMCRs to replace the preheating and pre-lube circuit hoses at a 5-year frequency and all hoses at a 10-year frequency.

During this inspection period, the inspectors discussed the maintenance history for the EDGs, DDCLP engines, and the DDFP engine with engineering and maintenance personnel and were concerned that the hoses on the D5/D6 EDGs had been installed for greater than the vendor recommended service life. As a result of these discussions, the licensee generated CAP 1361849 on December 4, 2012, to investigate the concern further.

The licensee reviewed completed work orders and walked down the in-scope systems to assess the condition of installed hoses. The licensee identified several locations on the D5/D6 high temperature coolant hoses where outer hose wrapping contained cracks to the point where the inner braided hose could be seen. Additional surface cracks were identified on D5 and D6 EDG hoses, similar to those documented during inspections performed in 2000 for the D5 EDG and in 2003 for the D6 EDG. The licensee evaluated the cracks and determined none of the cracks posed an immediate impact to EDG operability or the ability of the EDGs to meet their mission times. As a result of these efforts, the licensee scheduled the replacement of all hoses at the next available opportunities for D5/D6 EDGs. The D1 and D2 EDG hoses were replaced during the 1R28 refueling outage. The licensee also determined that the DDCLP hoses were not susceptible to the degradation mechanism of concern due to the hose design. The licensee inspected the DDFP hoses and identified four heavy steel mesh hoses which required additional assessment prior to developing replacement actions.

Analysis: The inspectors determined that the licensee's failure to account for potential degradation of components in the design of safety-related equipment was contrary to 10 CFR Part 50, Appendix B, Criterion III and was a performance deficiency. Specifically, the licensee did not recognize certain rubber hoses were susceptible to age-related degradation that could impact the safety function of the EDG. The issue was determined to be more than minor because, if left uncorrected, it had the potential to lead to a more significant safety concern. Specifically, the rubber hoses installed on D5 and D6 EDGs exceeded the vendor recommended service life and with no plans for periodic replacement, the hoses would further degrade.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings." Because the finding impacted the Mitigating Systems Cornerstone, the inspectors screened the finding through IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," using Exhibit 2, "Mitigating Systems Screening Questions." The finding screened as of very low safety significance (Green) because the finding was a qualification deficiency that did not represent a loss of operability or functionality. Due to the age of this issue, the inspectors concluded the cause of this finding was not reflective of current licensee performance and therefore, a cross cutting aspect was not assigned to this finding.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires in part, that the licensee shall establish measures for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of structures, systems, and components.

Contrary to this, prior to December 4, 2012, the licensee failed to establish measures for the review for suitability of application of materials. The licensee did not evaluate or review for suitability the use of rubber hoses beyond the vendor recommended service life. Specifically, several hoses in the D5 and D6 EDGs and in the DDFP have been installed beyond the vendor recommended service life of 10-years without further evaluation of acceptability. The licensee entered this issue into their CAP as CAP 1361849, evaluated the installed hoses condition, and replaced or scheduled the replacement of hoses installed longer than the recommended service interval. Because this violation was of very low safety significance and it was entered into the licensee's CAP, this violation is being treated as an NCV, consistent with the Enforcement Policy, **(NCV 05000282/2012005-03; 05000306/2012005-03: Failure to Account for Potential Age-Related Degradation in EDG Rubber Hoses)**.

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:

- Unit 2 increased risk due to Unit 1 electrical alignment; and
- Switchyard breaker 8H7.

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

Documents reviewed are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted two 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:

- 12 Diesel Driven Cooling Water Pump decreasing bearing water pressure;
- 121 Control Room Chiller relay degradation;
- Auxiliary Feedwater Pump Room Unit Cooler qualifications; and
- D5 EDG operability following D6 EDG radiator fan inoperability.

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 the 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 four samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- Engineering Change 20953 – Replacement of 121 Control Room Chiller Load Limit Relay with Solid State Control Device.

The inspectors reviewed the configuration change 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. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents; the modification operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modification 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 permanent plant modification sample as defined in IP 71111.18-05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 22 Diesel Driven Cooling Water Pump;
- Motor Valve 32071 – Accumulator Loop A Cold Leg Isolation Valve; and
- D2 EDG.

These activities were selected based upon the SSCs ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, 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 three post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 1 refueling outage (RFO), which began on October 23, 2012, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense in depth (DID). During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of DID commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment OOS;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup, tracking of startup prerequisites, walkdown of the primary containment to verify that debris has not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

A licensee identified NCV was documented regarding reactor vessel head removal activities. See Section 4OA7 for additional details.

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 1036 – Unit 1 Turbine Overspeed Trip Test (routine);
- SP 1071.5 – Unit 1 Containment Integrated Leak Rate Test (routine);
- SP 2102 – 22 Turbine Driven Auxiliary Water Pump Test (inservice test); and
- SP 1083A/B – Integrated Safety Injection with Loss of Offsite Power 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 three routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

A licensee identified NCV was documented regarding the performance of SP 2102. See Section 4OA7 of this report for additional details.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

The Nuclear Security and Incident Response staff performed an in-office review of the latest revisions of the Emergency Plan and various Emergency Plan Implementing Procedures (EPIPs) located under ADAMS accession numbers ML121220226 and ML121850150.

The licensee transmitted the EPIP revisions to the NRC pursuant to the requirements of 10 CFR Part 50, Appendix E, Section V, “Implementing Procedures.” The NRC review was not documented in a safety evaluation report and did not constitute approval of licensee-generated changes; therefore, this revision was subject to future inspection. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one emergency action level and emergency plan change inspection sample as defined in IP 71114.04.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational and Public Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

The inspection activities discussed below supplement those activities documented in NRC Inspection Report 05000282/2012002; 05000306/2012005. These activities constituted the completion of one inspection sample as defined in IP 71124.01-05.

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate the material condition of each area. The inspectors also performed independent radiation measurements in each area to verify the licensee’s documented radiological conditions.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors selected various containers holding nonexempt licensed radioactive materials that may cause unplanned or inadvertent exposure of workers, and assessed whether the containers were labeled and controlled in accordance with 10 CFR 20.1904, "Labeling Containers," or met the requirements of 10 CFR 20.1905(g), "Exemptions To Labeling Requirements."

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicated the presence of licensed radioactive material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters. The inspectors assessed whether or not the licensee had established a de facto "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high-radiation background area.

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact (i.e., they were not leaking their radioactive content).

The inspectors verified that any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, radiation work permits (RWPs), and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of electronic personal dosimeters in high noise areas as high radiation area (HRA) monitoring devices.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high-radiation work areas with significant dose rate gradients.

The inspectors examined the posting and physical controls for selected HRAs and very high radiation areas to verify conformance with the occupational performance indicator.

b. Findings

No findings were identified.

.5 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the significant radiological conditions in their workplace and the RWP controls/limits in place, and that their performance reflects the level of radiological hazards present.

b. Findings

No findings were identified.

2RS2 Occupational As-Low-As-Is-Reasonably-Achievable Planning and Controls (71124.02)

The inspection activities documented below supplement those activities documented in NRC Inspection Report 05000282/2012002; 05000306/2012002 and constituted a partial sample as defined in IP 71124.02-05.

.1 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in the licensee's as-low-as-is-reasonably-achievable (ALARA) planning for selected work activities. The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements, and evaluated the accuracy of these time estimates. The inspectors assessed the reasons (e.g., failure to adequately plan the activity, failure to provide sufficient work controls) for any inconsistencies between intended and actual work activity doses.

The inspectors determined whether post-job reviews were conducted and if identified problems were entered into the licensee's CAP.

b. Findings

No findings were identified.

.2 Radiation Worker Performance (02.05)

a. Inspection Scope

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or HRAs. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers are familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues (e.g., workers are not complying with work activity controls). The inspectors observed radiation worker performance to assess whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

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 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Residual Heat Removal System performance indicator (PI) for Unit 1 and Unit 2 for the period from the fourth quarter 2011 through the third quarter of 2012. 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 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event 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 issue report 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 MSPI residual heat removal system 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 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 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 six-month period of July 1, 2012 through December 31, 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

The inspectors also searched for trends related to issues which may have been documented outside the normal CAP. Areas inspected included 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 a single semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: Potential Emergency Action Level Implementation Issue due to Radiation Monitor 1R50 Extended Out of Service Time

a. Inspection Scope

On October 10, 2012, the Kewaunee Nuclear Power Plant submitted a 10 CFR 50.72 report to the NRC due to long term inoperability of an effluent radiation monitor and the impact that the inoperability had on the station's ability to declare specific EALs. Due to similarities between the Kewaunee site and the Prairie Island Nuclear Generating Plant, the inspectors conducted a review of this issue during the week of October 16, 2012. The inspectors reviewed the maintenance work history associated with effluent radiation monitors 1R50 and 2R50, searched the CAP database to locate issues associated with these radiation monitors, reviewed the Prairie Island specific EALs, and held discussions with emergency preparedness and regulatory affairs personnel.

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

b. Findings

During the CAP database review, the inspectors discovered that radiation monitor 1R50 had been out of service (OOS) from July 24, 2011 through May 25, 2012. The inspectors were concerned about the radiation monitor's extended period of inoperability because this monitor was relied upon to ensure that a General Emergency was declared in accordance with EAL RG1.1. The inspectors reviewed the Emergency Preparedness SDP and concluded that this issue had the potential to be risk significant. As a result, this issue was turned over to an NRC regional emergency preparedness inspector for additional review. The results of this additional review will be documented in NRC Inspection Report 05000282/2012504; 05000306/2012504.

.5 Selected Issue Follow-Up Inspection: Potential Impact On Implementation of E-0 Due to Lack of Control Room Indications

a. Inspection Scope

During a control room walkdown on February 16, 2012, the inspectors questioned why the indicating lights for the Unit 2 Control Rod Drive Mechanism (CRDM) Shroud and Fan Control Unit (FCU) Control Valve Indicating Lights were extinguished. Operations personnel informed the inspectors that the 21 Auxiliary Building/Containment Chiller had been removed from service for preventive maintenance. The inspectors questioned the control room operators regarding whether the extinguished lights constituted an operator work around. The inspectors were also concerned that the lack of light indication impacted the operators' ability to implement Emergency Operating Procedures 2E-0, "Reactor Scram or Safety Injection."

The licensee initiated CAP 1325309 to document the inspectors' questions. The licensee evaluated the loss of control room indications and determined this condition constituted an operator work around. The CAP recommended an Operating Instruction be issued when the Containment/Auxiliary Building Chillers were taken OOS for maintenance to ensure that the operators had awareness of the functionality of the related equipment. The licensee closed the CAP based on this recommendation without evaluating the potential impact on implementing Procedure 2E-0.

On October 22, 2012, the inspectors identified a similar control room condition where the CRDM Shroud and FCU Control Valve Indicating Lights were extinguished due to the 11 Auxiliary Building/Containment Chiller being OOS for maintenance. The licensee identified this issue via CAP 1355880. Due to similarities between the two issues, the inspectors conducted a review of the licensee actions associated with each CAP. The inspectors reviewed the CAPs, the associated supporting documentation, searched the CAP database to locate similar issues, reviewed emergency response procedures, and held discussions with operation personnel.

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

b. Findings

No findings were identified.

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

.1 (Closed) Licensee Event Report 05000282/2012-004: Unit 1 Emergency Diesel Generators Declared Inoperable due to High Ambient Temperature

a. Inspection Scope

The details surrounding this event, and a similar event that occurred in July 2012, are provided in Section 4OA5.1 of this report. Documents reviewed are listed in the Attachment to this report. This Licensee Event Report (LER) is closed.

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

b. Findings

An inspector identified finding of very low safety significance and an NCV are discussed in Section 4OA5.1 of this report. Please see this section for additional details.

.2 (Closed) Licensee Event Report 05000306/2012-002: Unit 2 Emergency Diesel Generators Inoperable Due to Missing Flood Barrier

a. Inspection Scope

On July 20, 2012, the licensee discovered that a concrete floor plug used to provide internal flooding protection for the D5 and D6 EDGs had been removed for an extended period of time. The licensee immediately declared both EDGs inoperable and re-installed the floor plug. The inspectors interviewed licensee personnel, walked down the flood barriers, reviewed the maintenance planning process, and reviewed corrective action documents to determine the sequence of events which led to removing a credited internal flooding barrier from the D5/D6 EDG area during June and July 2012. 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.

b. Findings

A licensee identified NCV of very low safety significance is discussed in Section 4OA7 of this report.

.3 Notice of Unusual Event Declared on October 31, 2012

a. Inspection Scope

On October 31, 2012, the licensee declared a Notice of Unusual Event (NOUE) due to a security related issue. The inspectors monitored the licensee’s response from the control room and specific security posts to ensure that the licensee was following their emergency plan/procedures and that appropriate compensatory measures were implemented. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

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

4OA5 Other Activities

.1 Operation of an Independent Spent Fuel Storage Facility Installation at Operating Plants (60855.1)

a. Inspection Scope

The inspectors observed and evaluated the licensee’s Independent Spent Fuel Storage Facility Installation (ISFSI) program to verify compliance with the applicable site specific license conditions, TS, and procedures.

The inspectors reviewed procedures related to ISFSI cask loading, movement, surveillance, and maintenance.

A tour was conducted of the ISFSI pad and storage casks to assess the condition of the ISFSI. No flammable or combustible materials were observed inside the ISFSI cask storage area, and inspectors reviewed evaluations of flammable materials outside the ISFSI area. The inspectors reviewed environmental radiation levels around the ISFSI, and reviewed the licensee’s radiation monitoring program for the ISFSI.

In addition, the inspectors reviewed a number of condition reports and the associated follow up actions since the last ISFSI inspection. The inspectors reviewed 10 CFR 72.48 screenings and evaluations.

At the time of the inspection the licensee was undergoing license renewal for the Part 72 site specific ISFSI. Aspects of license renewal, including the licensee’s proposed aging management plan were not inspected.

Transnuclear is under contract with Xcel Energy, operators of the Prairie Island Nuclear Generating Plant to design, fabricate, test and deliver nine TN-40HT spent fuel casks (casks 30-38) at Kobe Steel, Japan. Inspection Report 07200010/2012201 (ML12310A371) documented an NRC inspection that was conducted to verify that design, fabrication, and test activities were performed in accordance with the requirements of 10 CFR Parts 21, 71, and 72, the applicable site-specific license, TS, the Safety Analysis Report, and Transnuclear's Quality Assurance Program Manual, as a function of manufacturing.

b. Findings

Introduction: The inspectors identified an unresolved item (URI) due to the licensee’s discovery that they had not been assessing gauge uncertainties when completing ISFSI TS surveillance requirements.

Description: On November 17, 2010 the licensee wrote CAP 1259086. The CAP identified that the acceptance criteria in the D95.3 procedures had not accounted for the accuracy of the gauges when demonstrating compliance with the ISFSI TS.

This issue affected the acceptance criteria for both the vacuum drying test for casks 1-26 and the final cask helium backfill for casks 1-8. Regarding casks 1-26, a review of historical cask loading procedures identified that the procedural acceptance criteria for the vacuum drying test was 9.5 mbar with a TS limit of 10 mbar. This 0.5 mbar difference was not sufficient to account for the ±2 mbar gauge accuracy. Regarding casks 1-8, a review of historical cask loading procedures identified that the procedural acceptance criteria for the helium backfill utilized the same value that was listed in the ISFSI TS, 1400±70 mbar. The gauge utilized had ±10 mbar gauge accuracy. As part of the licensee's corrective actions, the licensee revised their procedural acceptance criteria to account for the gauge inaccuracy for future cask loading.

The inspectors reviewed the licensee's operability determination for the previously loaded casks and observed that the determination lacked quantitative data regarding issues that may arise due to the potentially inadequate amount of helium backfilled. In addition, the operability evaluation did not address the amount of oxidizing gases left in the canister due to potentially inadequate vacuum drying.

The inspectors reviewed the licensee's determination of whether ISFSI TS 3.1.1, "Cask Cavity Vacuum Drying," and ISFSI TS 3.1.2 "Cask Helium Backfill Pressure," was violated. The licensee determined that the neither TS 3.1.1 or 3.1.2 were violated.

The inspectors reviewed the licensee's reportability evaluation and observed that although the licensee screened the issue through the 10 CFR Part 50 reportability criteria and determined that the condition was not reportable, it was not apparent to the inspectors that the licensee screened the issue through the 10 CFR Part 72 reportability criteria.

This issue will be categorized as an unresolved item (URI) pending additional review by the inspectors regarding the licensee operability determination, TS compliance determination, reportability determination, and adequacy of corrective actions. The inspectors planned to consult with the office of Nuclear Material Safety and Safeguards, as necessary to resolve this issue. **(URI 072000010/2012001-01: Addition of Gauge Inaccuracy to Procedural Acceptance Criteria May Cause ISFSI Technical Specification Non-Compliance)**.

.2 <u>(Closed) Unresolved Item 05000282/2012003-05: Impact of Outside Air Temperature on D1 and D2 EDG Operability</u>

a. <u>Inspection Scope</u>

The inspectors reviewed information contained in NRC Integrated Inspection Reports (IRs) 05000282/2012003; 05000306/2012003 and 05000282/2012004; 05000306/2012004, the licensee's causal evaluation, and the results of pressure switch testing to determine whether a performance deficiency led to declaring the D1 and D2 EDGs inoperable on June 7, 2011 and July 2, 2012.

b. <u>Findings</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance (Green) and an NCV of 10 CFR Part 50, Appendix B, Criterion V, on June 26, 2012, due to the licensee's failure to have procedures appropriate to the circumstance for sufficiently coordinating and adequately preparing for the onset of hot weather conditions.

Specifically, Procedure FP-WM-SR-01, “Seasonal Readiness Program,” Attachment 2, failed to include criteria as part of the system material condition review such that issues associated with the ability of the Unit 1 EDGs to operate when outside air temperatures exceeded 97 degrees Fahrenheit (^{o}F) were identified and addressed prior to the onset of hot weather.

Description: On June 7, 2011, the licensee provided a 10 CFR 50.72 report to the NRC when both of the Unit 1 EDGs were declared inoperable due to outside air temperatures exceeding the operability limit of 100.5^{o}F. Several weeks later, the licensee retracted the 10 CFR 50.72 report based upon additional analysis which showed that the EDGs would remain operable up to a maximum outside air temperature of 102.5^{o}F.

On February 29, 2012, the licensee initiated CAP 1327157 to document that the analysis used to support the report retraction was non-conservative. The licensee completed a prompt operability determination, OPR 1327157-01, Revision 0, on April 15, 2012. This OPR concluded that the D1 and D2 EDGs were operable but non-conforming due to the non-conservatisms. The EDGs and support equipment were qualified to operate as long as the temperature inside the EDG rooms remained 120^{o}F or less. The licensee performed a computerized room heat up simulation and determined that the EDG rooms would remain less than or equal to 120^{o}F as long as the outside air temperature did not exceed 97^{o}F. As a result, the licensee established a revised outside air temperature operability limit of 97^{o}F for the Unit 1 EDGs.

During the week of June 26, 2012, the inspectors reviewed a past operability/reportability document regarding the EDG issues that occurred on June 7, 2011. The licensee determined that the June 2011 issue was not reportable to the NRC because the outside air temperature limit could be as high as 105^{o}F without impacting operability of the EDGs. The inspectors were concerned that the licensee’s technical justification for increasing the outside air temperature limit lacked technical rigor regarding why the installed lube oil pressure switches (EDG support equipment) would continue to perform their safety function at the increased air temperature. The inspectors discussed their concerns, and the impending weather forecast which predicted temperatures in excess of 97^{o}F, with engineering, operations, and licensee management personnel. Following these discussions, licensee management:

- Stopped all plans to use technical evaluations to increase the operability limit;
- Performed an additional review to determine whether the outside air temperature operability limit could be increased by installing additional and/or replacement components; and
- Reaffirmed that the D1 and D2 EDG outside air temperature operability limit was 97^{o}F.

The licensee reviewed the temperature qualifications for the equipment located in the EDG rooms. Following this review, the licensee determined that the outside air temperature operability limit could be increased if several lube oil pressure switches were replaced and the operability review was revised. The licensee replaced the D2 EDG lube oil pressure switches on July 1, 2012. However, actions were not taken to revise the temperature limits reflected in OPR 1327157-01 for the D2 EDG. On July 2, 2012, the outside air temperature exceeded 97^{o}F. Operations personnel immediately declared the D1 and D2 EDGs inoperable. The licensee also performed the following actions:

- The D1 EDG was removed from service to replace the lube oil pressure switches; and
- OPR 1327157-01 was revised to reflect the increase in the D2 EDG outside air temperature operability limit.

The shift manager approved the OPR revision within 2 hours. This allowed operations personnel to declare the D2 EDG operable. The D1 EDG was returned to service following the pressure switch installation.

The inspectors reviewed the licensee's causal evaluation for this issue and found that the licensee had identified the lube oil pressure switches as one of three limiting components on March 24, 2012. Following this discovery, the licensee established the 97°F operability limit and asked the EDG vendor to determine whether the operability limit could be increased. The licensee also placed this issue on their short term operational concerns list. Little action was taken to address this concern between March 24 and May 8, 2012 due to an ongoing Unit 2 refueling outage. The contract needed to support the EDG vendor's analysis was not issued until May 8, 2012, even though the vendor stated that the analysis would take two months to complete. In addition, the licensee had canceled the daily meeting used to discuss the short and long term operational concerns due to focusing on refueling outage activities.

On May 29, 2012, the licensee resumed holding daily meetings to discuss operational concerns. By this time the resolution of the D1 and D2 EDG outside air temperature issue had been extended to June 7, 2012. On June 7, 2012, the licensee extended the resolution date to September 1, 2012. The inspectors determined that the decision to cancel the daily meetings, and the failure to fully understand the operational impacts associated with extending the resolution date, contributed to the untimely resolution of this issue.

The inspectors also identified that the licensee's root cause evaluation was silent regarding whether any deficiencies in the seasonal readiness and/or the operability determination programs caused, or contributed to, the untimely resolution of the D1 and D2 EDG outside air temperature issue. The inspectors reviewed Procedure TP 1636, "Summer Plant Operation," and found that this procedure focused on aligning systems and components to support plant operation during the summer period. The inspectors reviewed Procedure FP-WM-SR-01, "Seasonal Readiness Program," and found that Step 4.1 of this procedure defined the summer period as May 15 through Labor Day. Step 5.1 of this procedure stated that each site Summer Readiness Coordinator shall maintain a site specific action item list that lists specific actions to be completed. Attachments were provided in the procedure to aid in identifying issues needing resolution.

The inspectors reviewed FP-WM-SR-01, Attachment 1, "Summer Readiness Action Timeline," and found the following on page 8:

- The System Engineer shall complete the system material condition reviews. Attachment 2 provides guidance for completing and documenting the reviews. The intent of the summer readiness period system reviews is not to duplicate system reviews but to ensure that the results of the reviews are analyzed and understood by the site. This review should occur early enough to allow any identified work to be completed prior to May 15th.

The inspectors requested the D1/D2 EDG material condition review from the licensee. The inspectors found that this review was completed. However, FP-WM-SR-01, Attachment 2, "System Engineering System Readiness Review," failed to include a review of the following:

- Short and long term operational issues that could lead to system operability or a reactor shutdown;
- Operable but degraded or operable but nonconforming conditions impacted by extreme weather conditions; and
- Performing a system walkdown for potential operability or reactor shutdown issues (walkdowns were performed to identify potential reactor trip or derate issues).

Due to the above issues, the inspectors determined that Procedure FP-WM-SR-01 was not appropriate to the circumstance.

Following a review of Procedure FP-OP-OL-01, "Operability/Functionality Determination," and NRC Inspection Manual Part 9900, "Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," the inspectors found that the industry standard for completing prompt operability determinations was 24 hours. Additional time was allowed as long as the risk associated with extending the operability determination completion time was evaluated. The timeline included in the licensee's root cause evaluation indicated that work requests to replace the lube oil pressure switches were initiated on June 26, 2012. While the licensee took action to revise OPR 1327157-01 in parallel with the pressure switch replacement, the licensee did not anticipate the possibility that the outside air temperature could exceed 97°F prior to all of the switches being replaced. This resulted in the licensee declaring the D2 EDG inoperable on July 2 even though the lube oil pressure switches had been replaced and D2 would have performed its specified safety function under all conditions.

Following the pressure switch replacement, the licensee sent the previously installed switches to an independent laboratory for testing. The laboratory testing consisted of exposing the pressure switches to a temperature of 130°F for 14 days to see if the switch operation was impacted by the temperature. The laboratory concluded that the increased temperature had no effect on the operation of the pressure switches. The inspectors reviewed the test results and had no concerns. Based upon the test results, the licensee concluded that the D1 and D2 EDGs would have remained capable of performing their safety function with the previous pressure switches installed.

<u>Analysis</u>: The inspectors determined that the failure to ensure that Procedure FP-WM-SR-01, "Seasonal Readiness Program," was appropriate to the circumstance such that issues which impacted the ability of safety related equipment to remain operable during extreme seasonal conditions was a performance deficiency that could be evaluated using the SDP. The inspectors determined that this issue was more than minor because it impacted the protection against external events objective of the Mitigating Systems Cornerstone. In addition, this finding impacted the cornerstone objective of ensuring the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the D1 EDG was rendered inoperable and unavailable to resolve potential issues with the lube oil pressure switches during a period of extreme heat.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 609.04, "Initial Characterization of Findings," and concluded that the significance of this finding should be determined using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions listed in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," could be answered "no." The inspectors determined that this finding was cross cutting in the Human Performance, Work Control area because Procedure FP-WM-SR-01 was not written to ensure that activities needed to support long term equipment reliability and availability were planned such that they were performed in a preventative manner rather than in a reactive manner (H.3(b)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, requires in part, that activities affecting quality be prescribed by instructions, procedures, and drawings appropriate to the circumstance.

Procedure FP-G-DOC-03, "Procedure Use and Adherence," defined activities affecting quality as those activities that affect or reasonably could affect the safety-related function of nuclear plant SSCs or parts. Those activities include designing, purchasing, fabricating, handling, shipping, storing, cleaning, erecting, installing, inspecting, testing, operating, maintaining, repairing, refueling and modifying. Based upon this, the inspectors determined that the seasonal readiness process was an activity affecting quality since it directed the inspection of safety related equipment and because the inspection results could affect safety related functions of plant SSCs or parts.

Contrary to the above, as of July 2, 2012, Procedure FP-WM-SR-01, "Seasonal Readiness Program," was not appropriate to the circumstance. Specifically, Attachment 2 of this procedure failed to include a review of short and long term operational concerns, operable but degraded and operable but nonconforming conditions, and potential system operability issues as part of the system material condition reviews. As a result, issues regarding the operability of the D1 and D2 EDGs when outside air temperature exceeded 97^{o}F were not identified and addressed prior to having to declare the EDGs inoperable due to extreme heat conditions.

Because this violation was of very low safety significance and it was entered into the licensee's CAP as CAPs 1327157, 1343946, 1365276 and 1365269, this issue is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2012005-04: Failure of Seasonal Readiness Procedure to Identify System Operability Issues)**. Corrective actions for this issue included reviewing FP-WM-SR-01 and making changes to ensure that items such as the EDG temperature issue would be identified and addressed during future seasonal readiness periods.

.3 (Closed) Unresolved Item 05000282/2012007-02; 05000306/2012007-02: Failure to Perform Maintenance Rule Evaluations After Discovering Degraded Radiation Monitors

a. Inspection Scope

The inspectors reviewed the results of the licensee's human performance review to determine the circumstances which led to not completing maintenance rule evaluations following the failure of multiple radiation monitors. The inspectors also reviewed the results of the subsequently completed maintenance rule evaluations to determine whether the evaluations met 10 CFR 50.65 requirements.

b. Findings

Introduction: A finding of very low safety significance (Green) and an NCV of 10 CFR 50.65 was identified by the inspectors due to the licensee's failure to demonstrate that the performance or condition of the radiation monitoring system was being effectively controlled through the performance of appropriate preventive maintenance such that the SSC remained capable of performing its intended function. Specifically, the licensee failed to perform maintenance rule evaluations following the failure of multiple radiation monitors in July 2010. Since the evaluations were not completed, the licensee was unable to demonstrate that the performance of the radiation monitors was being effectively controlled through the performance of maintenance.

Description: As discussed in NRC Problem Identification and Resolution Inspection Report 05000282/2012007; 05000306/2012007, the inspectors identified an URI due to the licensee's failure to complete maintenance rule evaluations following the discovery of several failed radiation monitors on approximately July 15, 2010.

The licensee reviewed the circumstances surrounding the failure to perform the maintenance rule evaluations and determined that this occurred because assignments to perform the evaluations were not initiated as part of the corrective action/action request process. This directly conflicted with Step 5.6.4.B of Procedure H24, "Maintenance Rule Program," which stated that maintenance rule evaluations were assigned as evaluations under the Action Request process and must be completed within 30 days as required by Procedure FP-PA-ARP-01, "Corrective Action Program."

The inspectors were provided completed maintenance rule evaluations for the radiation monitors in October 2012. The inspectors reviewed the evaluations and agreed that three out of four of the monitor failures were maintenance rule functional failures. However, the functional failures did not result in exceeding the maintenance rule performance criteria for the radiation monitoring system. The remaining radiation monitor issue was not a functional failure.

Analysis: The inspectors determined that the failure to demonstrate that the performance or condition of the radiation monitoring system was being effectively controlled through the performance of appropriate preventive maintenance was a performance deficiency that could be assessed using the SDP. The inspectors determined that this finding was more than minor because if left uncorrected the failure to perform maintenance rule evaluations could result in maintenance related deficiencies being undetected or unaddressed in safety related SSCs (a more significant safety concern). This performance deficiency impacted the equipment performance attribute of the Mitigating Systems Cornerstone. It also impacted this cornerstone's objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. This finding also impacted the SSC and barrier performance attribute of the Barrier Integrity Cornerstone by affecting reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents and events.

The inspectors utilized IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and concluded that the significance of this finding should be determined using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions listed in IMC 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” could be answered “no.” The inspectors determined that this finding was cross-cutting in the Problem Identification and Resolution, CAP area because the licensee failed to thoroughly evaluate this problem such that the resolution addressed the cause and extent of condition as necessary (P.1(c)).

Enforcement: Title 10 CFR 50.65(a)(1), requires, in part, that holders of an operating license shall monitor the performance or condition of SSCs within the scope of the rule as defined by 10 CFR 50.65(b), against licensee established goals, in a manner sufficient to provide reasonable assurance that such SSCs are capable of fulfilling their intended functions.

Title 10 CFR 50.65(a)(2) states, in part, that monitoring as specified in 10 CFR 50.65(a)(1) is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance such that the SSC remains capable of performing its intended function.

Contrary to the above, as of August 22, 2012, the licensee failed to demonstrate that the performance or condition of the radiation monitors included within the scope of the maintenance rule program were being effectively controlled through the performance of preventive maintenance. As a result, the performance of some radiation monitors was not being assessed against licensee established goals to provide reasonable assurance that the monitors were capable of performing their intended functions.

Because this violation was of very low safety significance, and it was entered into the licensee’s CAP as CAP 1347349, this violation is being treated as a NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2012005-05; 05000306/2012005-05: Failure to Demonstrate Performance or Condition of Radiation Monitoring System was Effectively Controlled)**. Corrective actions for this issue included completing the required maintenance rule evaluations and assessing the results against established goals.

.4 (Closed) NRC Temporary Instruction 2515/177, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-01)”

a. Inspection Scope

During an earlier inspection period, the inspectors verified the licensee had implemented or was in the process of implementing the commitments, modifications, and programmatically controlled actions described in the licensee’s response to NRC Generic Letter (GL) 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems.” This earlier activity was conducted in accordance with Temporary Instruction (TI) 2515/177 and was documented in NRC Inspection Report 05000282/2011003; 05000306/2011003. The TI remained open for the Prairie Island Nuclear Generating Plant because, at the conclusion of that inspection period, questions remained unresolved regarding some of the analytical methods used by the licensee to evaluate void transport behavior.

During this inspection period, the inspectors consulted with the Office of Nuclear Reactor Regulation (NRR) staff regarding the acceptability of the licensee’s analytical methods.

The NRC determined that further evaluation by NRR was required in order to better understand the acceptability of the licensee's analytical methods and determine an adequate resolution. Therefore, this issue is being followed up as a URI as described below. Based on the inspection results documented in NRC Inspection Report 05000282/2011003; 05000306/2011003 and tracking the resolution of the questions associated with the acceptability of the licensee's analytical methods for evaluating void transport behavior as an URI, this TI is considered closed.

Documents reviewed are listed in the Attachment to this report.

b. Findings

(1) Concerns with the Analytical Methods Used for Predicting Void Transport Behavior

Introduction: The inspectors identified a URI regarding the analytical methods used by the licensee for evaluating and predicting void transport behavior. Specifically, some methods used by the licensee relied on the use of computer software and test results which were previously questioned by the NRC staff. As a result, the inspectors questioned the acceptability of the analytical methods.

Description: On January 11, 2008, the NRC requested each addressee of GL 2008-01 to evaluate its Emergency Core Cooling System (ECCS), Decay Heat Removal, and Containment Spray (CS) systems licensing basis, design, testing, and corrective actions to ensure that gas accumulation (voids) was maintained less than the amount that would challenge the operability of these systems. Licensees were instructed to take appropriate actions when conditions adverse to quality were identified. As part of this effort, Prairie Island developed analytical methods for evaluating identified voids in the subject systems.

During a subsequent onsite inspection, the inspectors noted concerns with respect to the licensee's void assessment methodologies. Specifically, the inspectors noted the licensee relied on the use of computer codes to evaluate the acceptability of some voids. Specifically, the licensee used a combination of PIPER Q2.05, SYSFLO Q3.08, and AIRDST codes in their evaluations. The code, PIPER Q2.05, was used to generate a mathematical model of the piping in the form of control volumes and connectors. The control volumes represented the mass and energy of the fluid while the connectors represented the inertia of the fluid and the hydraulic resistance of the flow path. The SYSFLO Q3.08 code used this model to solve the mass, energy, and momentum conservation equations to obtain the pressure, temperature, and flow rate information. The AIRDST program used these results to simulate transport of air in the flow. The inspectors noted instances where the basis of this void assessment analysis tool was not well supported. Specifically, the licensee used WCAP-17271-P, "Air Water Transport in Large Diameter Piping Systems, Analysis and Evaluation of Large Diameter Testing Performed at Purdue," to show that the AIRDST code could acceptably predict quantitative void transport behavior. The inspectors noted the test configuration and conditions used in the WCAP-17271-P report differed from actual plant configuration and conditions, and questioned whether the application of some of the test results was acceptable. For example:

- The difference between test and plant pressures was not considered in assessing void decrease in the vertical test section. The pressure range used during the test was significantly lower than the typical range in nuclear power plants. Therefore, the inspectors questioned if the void fraction change observed during testing would be analogous in a nuclear power plant.

- Two phase fluid flow test data typically exhibited significant scatter. This was addressed by running many duplicate tests and carefully examining the test results. However, as documented in, “Forthcoming Meeting with the Nuclear Energy Institute to Discuss NRC Generic Letter 2008-01,” (ML090150637), the NRC stated this effort was not fully successful and some of the conclusions were not adequately supported by the test data due to data scatter. Specifically, this effort did not address allowances for uncertainty and the effect of actual plant pressures in contrast to test pressures.

- The inspectors questioned whether the test report adequately considered a “water fall” effect (also known as “hydraulic jump”) when the upper part of the vertical pipe was voided. Specifically, the inspectors questioned whether the pipe length used for the test was representative of the limiting conditions of a plant. The inspectors were concerned if such an effect could propel air further down in the pipe than would be predicted using a single dimensional Froude number and would be of concern if the vertical pipe length was significantly less than the pipe used for the test.

The inspectors also noted the evaluation which validated the use of AIRDST, Calculation 1067-1106-0038-00, “Comparison of Purdue Experimental Results to SYSFLO and AIRDST Program Predictions,” stated the repeatability of some of the test results was questionable. Specifically, the evaluation stated multiple readings did not always match with each other with the differences being significant. The evaluation also noted the AIRDST Program over-predicted and under-predicted void fractions depending on the conditions in the piping.

The inspectors discussed these observations with individuals from NRR. It was determined these observations required further evaluation by NRR to better understand the acceptability of the application of the test results contained in the WCAP-17271-P report to void assessment analysis.

The inspectors also noted that the licensee was unable to remove several voids which currently existed in the suction piping for the residual heat removal (RHR) and CS systems. The licensee justified the void acceptability using the above mentioned computer codes. Because of the inspectors’ questions associated with these computer codes, the licensee re-evaluated these voids using the conventional methods contained in “Guidance to NRC/NRR/DSS/SRXB Reviewers for Writing TI Suggestions for the Region Inspections” (ML103400347), and confirmed the voids met the acceptance criteria with the exception of the voids located between the containment sump ‘B’ isolation valves. These voids were procedurally created in order to alleviate pressure-locking concerns on these valves. Based on the information currently available, the licensee determined that these voids did not impact operability. The licensee was also evaluating potential modifications to address the voids.

Similarly, the inspectors noted the licensee had relied on these computer codes to justify the acceptability of previously identified voids (that no longer exist). The licensee also confirmed that these voids did not challenge system operability using NRR’s conventional method with two exceptions. Specifically, voids found at locations 2CS-06 and 1RH-03 were determined to exceed NRR's acceptance criteria when using the conventional method. The licensee used the simplified method contained in the WCAP-17276-P, "Investigation of Simplified Equation for Gas Transport," report and concluded the voids were acceptable. However, the inspectors noted the void at location 1RH-03 was acceptable per the simplified equation method; however, the void at location 2CS-06 did not meet the limitations of the simplified equation method. The inspectors consulted with NRR on the acceptability of this methodology and determined this methodology was also based on the same tests used to validate the computer codes. Because a void did not currently exist at locations 2CS-06 or 1RH-03, the inspectors determined the past operability of the CS and RHR systems would be addressed when NRR concluded their reviews on the use of computer software and the simplified equation methodology.

This issues discussed above were determined to be unresolved pending further evaluation of the licensee's analytical methods. The NRR staff will evaluate the matter and provide a determination on the acceptability of: (1) applying the test results contained in the WCAP-17271-P report to void assessment analysis; (2) the use of computer software for void transport analysis of the sump voids; and (3) using the simplified method contained in the WCAP-17276-P report for locations 1RH-03 and 2CS-06 **(URI 05000282/2012005-06; 05000306/2012005-06; Concerns with the Analytical Methods Used for Predicting Void Transport Behavior)**.

.5 <u>(Closed) NRC Temporary Instruction 2515/187, Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns, and NRC Temporary Instruction 2515/188, Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns</u>

a. <u>Inspection Scope</u>

The inspectors accompanied the licensee on a sampling basis, during their flooding and seismic walkdowns, to verify that the licensee's walkdown activities were conducted using the methodology endorsed by the NRC. These walkdowns were being performed at all sites in response to a letter from the NRC to licensees, entitled "Request for Information Pursuant to Title 10 of the *Code of Federal Regulations* 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident," dated March 12, 2012 (ADAMS Accession No. ML12053A340).

Enclosure 3 of the March 12, 2012, letter requested licensees to perform seismic walkdowns using an NRC-endorsed walkdown methodology. Electric Power Research Institute (EPRI) document 1025286 titled, "Seismic Walkdown Guidance," (ADAMS Accession No. ML12188A031) provided the NRC-endorsed methodology for performing seismic walkdowns to verify that plant features credited in the current licensing basis (CLB) for seismic events, were available, functional, and properly maintained.

Enclosure 4 of the letter requested licensees to perform external flooding walkdowns using an NRC-endorsed walkdown methodology (ADAMS Accession No. ML12056A050). Nuclear Energy Institute Document 12-07 titled, "Guidelines for Performing Verification Walkdowns of Plant Protection Features," (ADAMS Accession No. ML12173A215) provided the NRC-endorsed methodology for assessing external flood protection and mitigation capabilities to verify that plant features credited in the

CLB for protection and mitigation from external flood events, were available, functional, and properly maintained.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 10, 2013, the inspectors presented the inspection results to Mr. J. Lynch 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 review of the licensee's results of the annual operating test with Mr. T. Ouret, General Superintendent Operations Training, on November 1, 2012.

- The inspection results for the areas of radiological hazard assessment and exposure controls; and occupational ALARA planning and controls with Mr. K. Davison, Director Site Operations, on November 8, 2012.

- The results of the inservice inspection with Acting Site Vice-President, J. Sorensen, on November 16, 2012, and with J. Lynch, Site Vice-President on December 13, 2012.

- The results of the operation of an ISFSI inspection with J. Anderson, Regulatory Affairs Manager on January 9, 2013.

- The inspection results for the TI 2515/177 with Mr. J. Lynch, Site Vice President, on December 14, 2012.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) or Severity Level IV were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy for being dispositioned as NCVs.

- Title 10 CFR 50.65(a)(iv) requires, in part, that licensees must properly assess and manage risk. When the Unit 1 reactor was in a shut down condition, the licensee implemented 5 AWI 15.6.1, "Shutdown Safety Assessment," to assess and manage the risk as required by 10 CFR 50.65(a)(iv). Table 2 of 5 AWI 15.6.1 stated that no credit was to be given for the function/availability of the containment release barriers during the movement of heavy loads over irradiated fuel. Contrary to the above, on November 6, 2012, the licensee failed to properly assess the risk associated with moving the Unit 1 reactor vessel head. Specifically, operations personnel allowed credit to be given for the functionality/availability of multiple containment release barriers during the movement of the Unit 1 reactor vessel head (a heavy load) over irradiated fuel.

The inspectors assessed the significance of this finding using Checklist 3 of IMC 0609, Appendix G, Attachment 1, "Shutdown Operations Significance Determination Process Phase 1 Operational Checklists for Both PWRs and BWRs." The inspectors determined that this finding was of very low safety significance (Green) because the licensee met the containment control guidelines described in Section IV of Checklist 3 while moving the heavy load. The licensee documented this condition as CAP 1358291. Corrective actions for this issue included revising the shutdown safety assessment document, providing training to operations personnel that perform the shutdown safety assessment activities, and revising 5 AWI 15.6.1 to provide additional clarification regarding containment closure credit during the movement of heavy loads over irradiated fuel.

- Title 10 CFR Part 50, Appendix B, Criterion VIII, "Identification and Control of Materials, Parts and Components," states that measures shall be established for the identification and control of materials, parts and components, including partially fabricated assemblies. These measures shall assure that identification of the item is maintained by heat number, part number, serial number, or other appropriate means, either on the item or on records traceable to the item, as required throughout fabrication, erection, installation, and use of the item. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts and components. Contrary to the above, on May 22, September 14, November 1, and November 4, 2012, the design of the identification and control measures were not adequate to prevent the use of incorrect materials. Specifically, on the dates listed above, safety-related and/or augmented quality plant doors were repaired with parts whose identification were not maintained or were not traceable by an appropriate means.

  The inspectors assessed the significance of this issue using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors determined that this issue was of very low safety significance (Green) because Question A.1 was answered "yes," and Question B was answered "no." For those doors considered fire doors, the inspectors assessed the risk of this issue using IMC 0609, Appendix F, "Significance Determination Process for Fire Protection Issues." The inspectors assigned a fire confinement category to this issue since it was associated with fire doors. The inspectors assigned a low degradation rating to this finding as the performance and reliability of the doors was minimally impacted by the non-conforming parts. Per Task 1.3.1 of IMC 0609, Appendix F, this finding was also determined to be of very low safety significance (Green) due to the low degradation rating. The licensee documented this condition as CAP 1357789. Corrective actions for this issue included the implementation of a stop work order, declaring the doors functional but non-conforming, and ensuring that the non-conforming doors were repaired with the appropriate parts.

- Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures and drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures or drawings. Instructions, procedures or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, on October 24, 2012, the licensee failed to perform surveillance testing on the 22 Turbine Driven Auxiliary Feedwater (TDAFW) Pump (an activity affecting quality) with a procedure appropriate to the circumstance. Specifically, quantitative acceptance criteria contained in Surveillance Procedure SP 2102, "22 TDAFW Pump Monthly Test," was not updated to reflect a change in the baseline stroke time data for valve CV-31999, "22 TDAFW Pump Main Steam Supply Control Valve." As a result, CV-31999 failed to meet the procedurally indicated stroke time criteria. This required operation's personnel to declare the 22 TDAFW pump inoperable.

  The inspectors assessed the significance of this finding using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power." The inspectors determined that this issue was of very low safety significance (Green) because each of the questions contained in IMC 0609, Appendix A, Exhibit 2 could be answered "no." Specifically, a loss of function did not occur because the actual valve stroke time met the revised baseline acceptance criteria. The licensee documented this issue as CAP 1356385. Corrective actions for this issue included issuing the revised surveillance procedure, performing an extent of condition review, and ensuring that procedures which required revisions to their acceptance criteria were quarantined until the procedure revision was approved.

- Title 10 CFR 50.54(q)(2) requires that a holder of a nuclear power reactor operating license follow and maintain the effectiveness of an emergency plan that meets the requirements in Appendix E to this part and the planning standards of 10 CFR 50.47(b). The Prairie Island Nuclear Generating Plant (PINGP) Emergency Plan, Section 4.0 states in part, PINGP has and maintains the capability to assess, classify, and declare an emergency condition within 15 minutes after the availability of indications to plant operators that an EAL has been exceeded. Upon identification of the appropriate emergency classification level the emergency condition will be promptly declared. Contrary to the above, on October 31, 2012, the licensee failed to follow its Emergency Plan during an actual emergency which resulted in a failure to implement. Specifically, inaccurate communications resulted in the over classification of a NOUE based on EAL HU4.1.

  Using IMC 0609, Appendix B, "Emergency Preparedness Significance Determination Process," dated February 24, 2012, Section 4.0, "Actual Event Implementation Issue (Failure to Implement)," the inspectors determined that the violation was not greater than very low safety significance (Green) because no public official protective actions were implemented as a result of this event over classification. The issue was documented in the licensee's corrective action program as CAP 1357663. Corrective actions included making revision to emergency procedures regarding this type of security event and providing additional training to security personnel.

- Technical Specification 3.8.1 requires that two diesel generators capable of supplying the onsite 4 kV safeguards distribution system be operable when the reactor is operating in Modes 1, 2, 3 or 4.

  With one diesel generator inoperable, Limiting Condition for Operation (LCO) 3.8.1.b requires that the diesel generator be returned to service within 14 days.

  With both diesel generators inoperable, LCO 3.8.1.e requires that one diesel generator be restored to an operable status within 2 hours.

  Contrary to the above, on June 25 and July 9, 2012, the D5 and D6 diesel generators were not restored to an operable status within two hours of removing a concrete trench which served as a barrier to protect the diesel generators from the impact of an internal flood. Per Procedure 5AWI 8.9.0, “Internal Flooding Drainage Control,” the concrete trench cover must be in place to support diesel generator operability whenever there is a possibility of a HELB in the Unit 2 turbine building.

  The inspectors performed a significance screening of this finding using the guidance provided in IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process for Findings At-Power." In accordance with Exhibit 2, "Mitigating Systems Screening Questions," the inspectors answered "Yes" to the screening question "Does the finding represent a loss of system and/or function?" since there was the potential for the D5 and D6 emergency power sources to be rendered unavailable. The exposure time for the performance deficiency was the period of time that the flood barrier was missing, which was the 25-day period from June 25 to July 20, 2012.

  In order to affect an increase in plant risk, the D5 and D6 diesel generators would have to be rendered unavailable by some type of flooding event concurrent with a loss of offsite power (LOOP) event. This scenario was assumed to occur during a seismic event which causes a LOOP along with certain pipe breaks. Such pipe breaks can result from direct seismic failures of the piping itself or indirectly from seismic-induced HELB events that in turn break other piping in the turbine building.

  The NRC performed a detailed SDP analysis for a separate turbine building flooding issue that bounds this issue. On May 27, 2010, the NRC issued Inspection Report 05000282/2010010; 05000306/2010010 (EA-10-070; ML101470607). This inspection report contained the NRC's preliminary risk analysis to assess the impact on both units due to the failure to ensure that engineered safety features, including the diesel generators, were not adversely affected by events that cause turbine building flooding. A subset of that analysis is relevant for this current performance deficiency; namely, the seismic-induced failure of piping for Unit 2.

The NRC later completed its final risk analysis based, in part, on the licensee's analysis from a report titled "Turbine Building HELB/Internal Flooding Significance Determination Process," which included a Main Report and seven Addendums (dated June 25, 2010). In Addendum 7, "Seismic Analysis and Quantification," the licensee performed a detailed SDP analysis of seismic initiating events. The senior reactor analyst (SRA) used that part of the licensee's seismic analysis to assess the risk for this current performance deficiency.

The resultant seismic-induced flood risk increase for Unit 2 was 1.98E-6 for an entire year, which equated to a risk increase of 1.4E-7/yr for the 25-day exposure period. This value is conservative since it included non-LOOP as well as LOOP events. Since only 18 percent of the Unit 2 sequences involved LOOP flooding scenarios, the SRA determined that the change in core damage frequency (ΔCDF) for this finding would be approximately 2.5E-8/yr. The dominant sequence involved a station blackout with pipe breaks associated with these pieces of equipment: generator hydrogen cooler, generator exciter cooler, hydrogen seal oil unit cooler, condensate pump motor unit coolers, miscellaneous small piping, and multiple fire protection components.

Based on the above, the SRA concluded that the total risk increase to the plant due this finding based on CDF was very low (Green). The licensee documented this issue in the CAP as CAP 1345525. Corrective actions included re-installing the flood barrier, labeling the flood barrier, and ensuring that information was readily available to alert plant personnel to the fact that the concrete trench cover was used as an internal flooding barrier.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Lynch, Site Vice President
K. Davison, Director – Site Operations
P. Huffman, Site Engineering Director
S. Sharp, Plant Manager
T. Allen, Assistant Plant Manager
J. Anderson, Regulatory Affairs Manager
J. Boesch, Maintenance Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
D. Gauger, Chemistry/Environmental Manager
J. Hamilton, Security Manager
J. Lash, Nuclear Oversight Manager
S. Lappegaard, Production Planning Manager
B. Meek, Safety and Human Performance Manager
O. Nelson, ISFSI Project Engineer
K. Peterson, Business Support Manager
R. Puddu, Performance Assessment Manager
J. Ruttar, Operations Manager

Nuclear Regulatory Commission

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

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000282/2012005-01	NCV	Failure to Disposition a Relevant Snubber Indication in accordance with the ASME Code (Section 1R08)
05000282/2012005-02; 05000306/2012005-02	FIN	Inadequate Evaluation of Operating Crew during Annual Requalification Examination (Section 1R11)
05000306/2012005-03	NCV	Failure to Replace Rubber Hoses on D5 and D6 EDG in accordance with Vendor Recommendations (Section 1R12)
07200010/2012001-01	URI	Addition of Gauge Inaccuracy to Procedural Acceptance Criteria May Cause ISFSI TS Non-Compliance (Section 4OA3.1)
05000282/2012005-04	NCV	Failure of Seasonal Readiness Procedure to Identify Operability Issues (Section 4OA5.2)
05000282/2012005-05; 05000306/2012005-05	NCV	Failure to Demonstrate Performance or Condition of Radiation Monitors were Effectively Controlled Through the Performance of Maintenance (Section 4OA5.3)
05000282/2012005-06; 05000306/2012005-06	URI	Concerns with Analytical Methods used for Predicting Void Transport Behavior (Section 4OA5.4)

Closed

05000282/2012005-01	NCV	Failure to Disposition a Relevant Snubber Indication in accordance with the ASME Code
05000282/2012005-02; 05000306/2012005-02	FIN	Inadequate Evaluation of Operating Crew during Annual Requalification Examination
05000306/2012005-03	NCV	Failure to Replace Rubber Hoses on D5 and D6 EDG in accordance with Vendor Recommendations
05000282/2012005-04	NCV	Failure of Seasonal Readiness Procedure to Identify Operability Issues
05000282/2012005-05; 05000306/2012005-05	NCV	Failure to Demonstrate Performance or Condition of Radiation Monitors were Effectively Controlled Through the Performance of Maintenance
05000282/2012-004	LER	Unit 1 Emergency Diesel Generators Declared Inoperable Due to High Ambient Temperature
05000306/2012-002	LER	Unit 2 Emergency Diesel Generators Inoperable Due to Missing Flood Barrier

05000282/2012003-05	URI	Impact of Outside Air Temperatures on D1 and D2 EDGs
05000282/2012007-02; 05000306/2012007-02:	URI	Failure to Perform Maintenance Rule Evaluations After Discovering Degraded Radiation Monitors
2515/177	TI	Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems
2515/187	TI	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns
2515/188	TI	Inspection of Near-Term Task Force Recommendation 2.3 Seismic Walkdowns

<u>Discussed</u>

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.

1R04 Equipment Alignment

- C1.1.20.7-1; D1 Diesel Generator Valve Status; Revision 23
- C1.1.20.7-2; D1 Diesel Generator Auxiliaries and Room Cooling Local Panels; Revision 11
- C1.1.20.7-3; Diesel Generator D1 Main Control Room Switch and Indicating Light Status; Revision 15
- C1.1.20.7-4; D1 Diesel Generator Circuit Breakers and Panel Switches; Revision 12
- C1.1.35-3; Cooling Water System; Revision 31
- CAP 1339405; 22 TDAFWP Turbine OB BRG >203F During SP 2103, May 29, 2012
- CAP 1347546; CV-31999, 22 TD AFW PMP MS SPLY CV Has Adverse Trend, August 8, 2012
- CAP 1356782; 2012 Fukushima Flooding Walkdowns: Degraded Cap on Pipe; October 27, 2012
- CAP 1356938; 2012 Fukushima: No Details on Penetrations Through Flood Wall; October 29, 2012
- CAP 1356972; 2012 Fukushima: Rodd Drain Piping with Victaulic Couplings; October 29, 2012
- CAP 1356975; 2012 Fukushima: Lack of Configuration for Penetrations; October 29, 2012
- CAP 1357039; 2012 Fukushima Flooding Walkdowns – AB-4 Suggestions; October 30, 2012
- CAP 1357431; 2012 Fukushima: Configuration of Conduit Ends in Screenhouse; November 1, 2012
- CAP 1357449; 2012 Fukushima: D5-D6 Cannot Verify Internal Seal in Conduit; November 1, 2012
- CAP 1357457; 2012 Fukushima: Cracked Penetration Seal on Cooling Water Dump to Grade; November 1, 2012
- CAP 1357903; 2012 Fukushima: External Flood Wall Physical Margin; November 5, 2012
- CAP 1358340; Whip Restraint 46-AFW-16 Lack of Thread Engagement, November 8, 2012
- CAP 1359717; Snubber 1-AFWH-84 has nicks on the piston shaft, November 17, 2012
- CAP 1361270; 2AF-33-2 Slight Packing Leak, November 29, 2012
- CAP 1361284; PINGP 1198 Scaffold Form Not to Standards, November 29, 2012
- Checklist C28-16; 21 Motor Driven Auxiliary Feedwater Pump, Revision 6
- Checklist C28-18; 22 Turbine Driven Auxiliary Feedwater Pump, Revision 9
- Checklist C28-7; Auxiliary Feedwater System Unit 2, Revision 53
- Control Room Narrative Logs, Various
- EC 21098; Evaluation of Lack of Thread Engagement and Missing Washer 46-AFW, November 20, 2012
- PINGP—System Health Report; Auxiliary Feedwater, July 20, 2012
- Procedure 2C28.1; Auxiliary Feedwater System Unit 2, Revision 25
- Procedure D18; Equipment Lubrication, Revision 86
- Procedure PM 3132-1-22; 22 TDAFWP Minor Periodic Maintenance, Revision 48
- SP 1293; Inspection of Flood Control Measures; Revision 22
- SWI O-3; Safeguards Hold Cards & Component Blocking or Locking, Revision 82
- Technical Requirements Manual

- Technical Specifications and Bases
- WO 371272; U2, 22 TD AFWP, Replace Governor VLV Bonnet, May 6, 2012
- WO 409544; PM 3132-1-22 TD AFWP (245-201) Minor Maintenance, April 4, 2012
- WO 409833; SP 2103 22 TDAFWP Once Every RFL SHDN Flow Test, May 29, 2012
- WO 409835; SP 2330-22 TDAFW Turbine/PMP Bearing Temp Test, May 26, 2012
- WO 436003; SP 2102 22 Turbine-Driven AFW Pump Monthly Test, July 19, 2012
- WO 460580; 22 TD AFW PMP TURB OBRG Temp in the Alert Range, May 27, 2012
- WO468565; Perform Operational Readiness Test SNUB 1-AFWH-84

1R05 Fire Protection

- CAP 1168468; Door 1221 Sealing Issue: February 6, 2012
- CAP 1310438; 2011 FP FSA: Large # of FP Equipment Impairments Observed; October 28, 2011
- CAP 1312153; Inadequate Barrier Separation Between Bus 26 & 27 RMS; November 8, 2011
- CAP 1320395; Potential Undocumented TMOD; January 12, 2012
- CAP 1333436; Inadequate Station Action to Correct Fire Impairments; April 11, 2012
- EC 19393; Temporary Fire Barrier Between Bus 26 and 27 Rooms; February 20,2012
- ENG-ME-094 Attachment 9.3; Fire Load Calculation Sheets; Revision 5
- FPEE-09-001; Fire Protection Engineering Evaluation for the Use of Pearl Weave; Revision 1
- PINGP Impairment Report for All Fire Areas; November 30, 2012
- Procedure C37.9 AOP 1; Loss of Control Room Cooling; Revision 13
- Procedure F5 Appendix A; Fire Zone Plans and Maps; Various Revisions
- Procedure F5 Appendix F; Fire Hazard Analysis; Revision 27
- WO 446270; Fix Wall Between Bus 26 & 27 Rooms
- WR 42651; Door 121; February 6, 2012
- WR 43596; Excessive Door Frame Gap

1R08 Inservice Inspection

- 5AWI 14.6.0; ASME Section XI Inservice Inspection and Pressure Testing; Revision 14
- BACC CE 1197934; BA Indication Evaluation on MV-32231, RCS Loop B; May 5, 2011
- BACC CE 1284002; Body to Bonnet Gasket Leak, BA Indication on the MV-32083 Fasteners; May 20, 2011
- BACC CE 1284031; BA Indication Evaluation on CV-31325 2” CVCS System Valve; November 17, 2011
- BACC CE 1356914; RH-2-6, RHR Heat Exchanger Outlet Crosstie, Body-to-Bonnet BA Indication Evaluation; November 7, 2012
- CAP 1283239; 11 RSG Secondary Side Leak; May 30, 2011
- CAP 1284031; ASME XI Relevant Boric Acid Flange Leak on CV-31325; November 2, 2012
- CAP 1285037; ASME Relevant Boric Acid Leakage on RH-2-6; November 25, 2011
- CAP 1285151; ISI Indications on Support RCVCH-896; May 11, 2011
- CAP 1285744; ISI Indication 12 Steam Generator Snubber Supports; June 14, 2011
- CAP 1287563: ISI Indication on Support RCVCH-922; May 25, 2011
- CAP 1299806; Boric Acid Fitting Leak above RC-8-32; May 31, 2012
- CAP 1312553; Corrosion Evaluation Required for MV-32074; May 31, 2012
- CAP 1358172; Question on Item No. for IWE Containment Bolting; November 7, 2012
- CAP 1359101; Inadequate Disposition of Snubber Low Level 12S/G01; November 14, 2012
- FP-PE-NDE-520; Visual Examination for Leakage, VT-2; Revision 5
- FP-PE-NDE-530; Visual Examination, VT-3; Revision 6
- H2; Boric Acid Corrosion Control Program; Revision 19

- Report No. 2011V030; VT-3 of Snubber H-1; May 7, 2011
- Report No. 2011V031; VT-3 of Snubber H-2; May 7, 2011
- Report No. 2011V032; VT-3 of Snubber H-3; May 7, 2011
- Report No. 2011V033; VT-3 of Snubber H-4; May 7, 2011
- SP 1070; Reactor Coolant System Integrity Test; Revision 43
- SP 1405; Unit 1 Mid-Cycle and Refueling Outage Boric Acid Corrosion Examinations Inside Containment; Revision 9
- SP1392; Unit 1 Insulated Bolted Connection Inspection; Revision 10
- WO 00090107; Replace Valve MV-32043; November 17, 2010
- WO 00408560; Repair PT Indication on 1-RCVCH-896; May 31, 2011

<u>1R11 Licensed Operator Requalification</u>

- CAP 1355481; Potential exam security concern;
- Prairie Island NRC Exam Results; November 1, 2012
- QF-1073-02; Crew Operator Simulator Examination Summary; October 2, 2012

<u>1R12 Maintenance Effectiveness</u>

- System Health Report; 480V Breakers; November 17, 2012

<u>1R13 Maintenance Risk and Emergent Work</u>

- Work Week Safety Profile; dated October 13, 2012 and November 17, 2012

<u>1R15 Operability Evaluations</u>

- C35; Cooling Water; Revision 74
- CAP 1307272; CDBR: Parts Downgrade M-0005 For Pump Mechanical Seals Lacks Rigor; October 6, 2011
- CAP 1324699; Immediate Operability Determination Of CAP 1307272; February 11, 2012
- CAP 1348162; Void CAPs Contain Insufficient Operability Information; August 14, 2012
- CAP 1354108; Possible Plugging of 12 Diesel Driven Cooling Water Pump Bearing Seal Water Lines; October 5, 2012
- CAP 1354692; 121 CR Chiller Operation Sluggish Following S/U
- CAP 1355477; During PMT for PM 3138-2 and TP 1687 121 CR Failed to Load; October 17, 2012
- CAP 1357609; CDBR: Unit Cooler Motor Design Limit Evaluation Auxiliary Feedwater Pump Rooms; November 2, 2012
- CAP 1359429; 1R28 1R-YS Supply to Bus 15 as-found Condition; November 15, 2012
- OPR 1266815-02; Evaluation of Auxiliary Feedwater Room Heat Removal Capabilities; Revision 5
- Procedure C37.11; Chilled Water Safeguard System Operation; Revision 24
- SOMS Narrative Log Search - 121 Entries; October 12 To October 13, 2012
- SOMS Narrative Log Search - Chiller Entries; Various Dates From October 11 To October 20, 2012
- WO Package 00466478; 121 Control Room Chiller Operation Sluggish Following Startup; no date provided

1R18 Plant Modifications

- 50.59 Screening No. 4120; EC-20953 – 121 Chiller Unit Load Limiting Controller; Revision 1; October 24, 2012
- CAP 1319983; CDBR: Modifications Installed Without Supporting Design Doc; January 9, 2012
- CAP 1356587; EC 20953 Failed To Include Seismic Qualification Of Load Limiter; October 26, 2012
- CAP Modification Turned Over – Documentation Not Complete
- DBD STR-02; Auxiliary Building; Revision 5
- Dedication No. 2006-007; Commercial Grade Dedication Evaluation; Revision 02; Completed April 27, 2009
- Drawing NE-40008-85; Control Room Chiller Unit; Revision 76
- Drawing NE-40008-87; 121 Control Room Water Chiller Control Circuit; Revision 77
- Drawing XH-483-7; Internal Panel Wiring Diagram 121 & 122 Control Room Chiller Unit Instrument Panels; Revision 75
- EC No. 20953; Replacement Of 121 Chiller Load Limit Relay With Solid State Control Device; Revision 0; October 24, 2012
- Evaluation No. PI-0040; Commercial Grade Application Evaluation For Trane Centravac Chiller Spare Parts; Completed March 17, 1995
- SE-0401 Action Tracking Search Engine; Subject: Modification;' All Items From January 1 To November 21, 2012
- Trane General Service Bulletin; CTV-SB-80; Replacing Pneumatic Load Limit Relay (RLY-23) With Solid-State Control CNT-1064
- Trane General Service Bulletin; CTV-SB-85; Solid-State Load Limit Control CNT1064 and Current Transformer Mismatch
- USAR Section 10; Safeguards Chilled Water System; Revision 31
- WO 466934; Replace 121 CR CLR Refrg. Gas inlet Vane Load Limit Relay

1R19 Post Maintenance Testing

- Condition Evaluation 1202567; Motor Valve 32071 Corrosion Evaluation; no date provided
- WO 404615; Motor Valve 32071 Accumulator Loop A Cold Leg Isolation Motor Valve Maintenance; November 19, 2012

1R20 Refueling and Outage

- C47002; Alarm Response Procedure 47002-0103 (11/12/13 Feedwater Heater Hi Hi Level); Revision 12
- CAP 1356338; White Residue on the Unit 1 Reactor Head; October 24, 2012
- CAP 1357694; Adverse Slope Found in Unit 1 RCGVS; November 2, 2012
- CAP 1359429; 1R-YS Supply to Bus 15 As-Found Condition; November 15, 2012
- CAP 1363051; Bus 16-8 Cables – Tan Delta Assessment Tested out of Specification; December 12, 2012
- CAP 1363369; Negative Slope Still Exists After Head Vent Pipe Modified; December 14, 2012
- D58.1.10; Unit 1 Reactor Vessel Head Replacement; Revisions 8
- D58.1.9; Unit 1 Reactor Vessel Head Removal; Revision 20
- FP-OP-COO-01; Conduct of Operations; Revision 12
- Operations Training Lesson Plan 9112C-0205; Engineering Change 19795 – Addition of Reactor Coolant Gas Vent Drain Valve; Revision 0
- Operations Training Lesson Plan 9112L-0501; Outage Training; Revision 0

- Operations Training Lesson Plan 9112L-0507; Excellence in Operator Fundamentals at Prairie Island; Revision 0
- Operations Training Lesson Plan P9160S-004, Attachment 2; Reactor Coolant System Draindown Just in Time Training; Revision 0
- SP 1177; Refuel Core Inventory Verification; Revision 17
- SP 1750; Post Containment Close-Out Inspection; Revision 038
- SWI-O-50; Reactivity Management; Revision 17
- U1R28 Core Inventory Verification; December 2012
- Unit 1 Restart Readiness Review Emergent Plant Operating Review Committee Meeting #3263 (Part I); December 22, 2012
- Unit 1 Restart Readiness Review Emergent Plant Operating Review Committee Meeting #3263 (Part II); December 27, 2012
- Unit One Refueling Outage October 2012 Shutdown Safety Assessment; Revision Dated 10/10/2012
- WO 396712; SP-1177 Refuel Core Inventory Verification; December 2012
- WO 426112-01; D58.1.9; Reactor Vessel Head Replacement; December 2012
- WO 436183-01; D58.1.10 Reactor Vessel Head Removal; November 2012
- C1B; Appendix – Reactor Startup; Revision 19
- 1C5; Control Rod And Rod Position Indication Systems; Revision 16
- D30; Post Refueling Startup Testing; Revision 52
- C1.M2; Surveillance Requirements Mode 2, Startup; Revision 16

1R22 Surveillance Testing

- CAP 1356385; Control Valve 31999 – 22 Turbine Driven Auxiliary Feedwater Pump Main Steam Supply Timed Too Slow; October 25, 2012
- SP 1036; Turbine Overspeed Trip Test; Revision 30
- SP 1071.5; Integrated Leakage Rate Test Final Preparations and Test Procedure; Revision 16
- Unit 1 Integrated Leakage Rate Test Results; October 29-30, 2012
- WO 396627; SP1036 Turbine Overspeed Trip Test and Setpoint Verification; October 22, 2012

1EP4 Emergency Action Level and Emergency Plan Changes

- Emergency Plan; Revision 46
- F3-2.1; Emergency Action Level Technical Bases; Revision 8
- F3-2; Classification of Emergencies; Revision 43
- F3-6; Activation and Operation of Technical Support Center; Revision 25
- F3-8; Recommendations for Offsite Protective Actions; Revision 34
- F8-3; Activation and Operation of the EOF; Revision 12
- PINGP 1576; Emergency Action Level Matrix; Revision 7

2RS1 Radiological Hazard Assessment and Exposure Controls

- CAP 1345460; Radioactive Sources Not Found in Normal Location; July 19, 2012
- CAP 1345610; Annual Source Inventory Location Discrepancies; July 21, 2012
- CAP 1358169; Sources Listed in Source Inventory Not Inventoried; November 7, 2012
- FG-RP-RMS-01; Installation/Setup of Remote Monitoring; Revision 00
- FG-RP-RMS-02; Operation of RMS Equipment; Revision 00
- FP-RP-CRS-01; Control, Inventory and Leak Testing of Radioactive Sources; Revision 10
- FP-RP-RM-01; Conduct of Radiation Protection for Remote Monitoring; Revision 00

- FP-RP-RM-02; RMS Response to Warnings/Alarms and Equipment Failures; Revision 00
- FP-RP-SD-01; Special Dosimetry; Revision 7
- National Source Tracking System Records; Prairie Island Nuclear Generating Station; November 8, 2012
- NOS Observation Report 2012-01-025; Radiation Protection; March 31, 2012
- NOS Observation Report 2012-02-003; Radiation Protection; May 3, 2012
- Nuclear Oversight 4th Quarter 2011 Assessment Report for Prairie Island; February 10, 2012
- Radioactive Source Inventory; November 7, 2012
- Radioactive Source Leak Tests Results; November 7, 2012
- RPIP 1120; Posting of Restricted Areas; Revision 36
- RPIP 1300; Control and Tagging of Radioactive Material; Revision 21
- RPIP 1302; Unconditional Release of Materials; Revision 23
- RPIP 1331; Radioactive Material Control; Revision 00
- RPIP 1677; SAM-11 Small Articles Monitor Operation and Calibration; Revision 5
- RWP 1163; Unit 1 RCP Work; November 6, 2012
- RWP 1259; Unit 1 Seal Table Work; November 6, 2012
- RWP 1263; Unit 1 Remove Rx Head to Stand on 715 Elevation; November 6, 2012
- RWP 1564; Work on Internals of SI Check Valves – LHRA; November 6, 2012
- SAM-11 Small Articles Monitor Calibration Sheets; Various dates 2012
- Sentinel ED Alarm Logs; November 8, 2012
- SP 1170; Special Nuclear Material Inventory; Revision 30; April 10, 2012

2RS2 Occupational ALARA Planning and Controls

- 1R28 Radiation Protection Department Outage Manual; undated
- Daily Outage Report; Prairie Island Refuel Outage 1R28; various dates
- List of 1R28 Outage RWPs and Radiological Work Orders; November 6, 2012

4OA1 Performance Indicator Verification

- CAP 1354673; Dedicated Operator Needed for 22 Diesel Driven Cooling Water Pump during SP 1106B; October 10, 2012

4OA2 Problem Identification and Resolution

- 10 CFR 50.54(q) Screening PI-2012-36; 1R50 High Range Shield Building Vent Gas Monitor Out of Service since July 2011; June 25, 2012
- 1E-0; Reactor Trip or Safety Injection; Revision 29 & 30
- 1R-50 Shield Building HI RANGE Vent Gas Radiation Detector White Paper
- 2E-0; Reactor Trip or Safety Injection; Revision 29
- CAP 1295912; 1R-50 Monitor Failed; July 24, 2012
- CAP 1325309; Operations Burden For No CRDM Shroud and FCU Control Valve Indicating Lights; February 16, 2012
- CAP 1325419; FP-EP-EQP-01 EP Notification for 50.54(q) Evaluation; February 17, 2012
- CAP 1330524; 1R-50 WO Priority Questioned; March 23, 2012
- CAP 1338120; 1R-50 Repair Priority Incorrect; March 17, 2012
- CAP 1355447; Reporting Vulnerability to Radiation Monitor Out of Service; October 17, 2012
- CAP 1355880; 11 Containment/Auxiliary Building Chiller Isolation Prevents E-0 Attachment L Step; October 22, 2012
- CAP 1357281; 1R50 Out of Service from July 24, 2011 until May 25, 2012; October 31, 2012
- CAP 1361215; Missed Planning Standard 8 during 50.54(q) Evaluation; November 29, 2012

- F3; Determination of Radioactive Release Concentrations; Revision 22
- FP-EP-EQP-01; Equipment Important to Emergency Preparedness; Revision 0
- FP-R-EP-02; 10 CFR 50.54(q) Review Process; Revision 8
- FP-WM-WOI-01; Work Identification, Screening, Validation, and Cancellation; Revision 14
- Operating Logs regarding Radiation Monitors 1R50 and 2R50; dated July 24, 2011 through October 22, 2012
- PINGP 1576; EAL Matrix; Revision 7
- PINGP 1672; Equipment Important to Emergency Preparedness; Revision 6
- Prairie Island Nuclear Generating Plant Emergency Action Level Chart
- WO 437648; Replace Detector Preamp for 1RE-50; May 17, 2012

<u>4OA3 Event Followup and Notices of Enforcement Discretion</u>

- 5 AWI 8.9.0; Internal Flooding Drainage Control; Revision 8
- Altran Solutions Report 12-1297-TR-001; Laboratory Evaluation of Two EDG Pressure Switches; Revision 0
- CAP 1357566; NUE HU4.1 Declared 10/31/12 Event Response; November 2, 2012
- CAP 1357663; Security NUE Classification; November 2, 2012
- CAP 1357722; NUE Response – Event Response not Formally Initiated by Station Duty Manager; November 3, 2012
- CAP 1357723; NUE Response – Control Room Layout Issues; November 3, 2012
- Causal Evaluation 1345525; Concrete Pipe Trench Cover Removed in D5/D6 Building; October 5, 2012
- Engineering Change 20845; Temporary Measures to Permit Removing Trench Covers in D5/D6 Building; Revision 0
- Engineering Change 21014; Past Operability for Heat-up Analysis for D1/D2 for Revised Outside Air Temperature Limit; Revision 0
- Human Performance Event Review for Notice of Unusual Event; November 1, 2012
- Prairie Island Design Basis Document TOP-05; Hazards; Revision 4
- Regulatory Issue Summary 2001-009; Control of Hazard Barriers; April 2, 2001
- Updated Safety Analysis Report Section 6.1.2.8; Engineered Safety Features Protection from Internal Flooding; Revision 32P

<u>4OA5 Other Activities</u>

- 2011 Annual Radiological Environmental Monitoring Program Report; May 11, 2012
- 72.48-1092; Definition of Helium Environment Within Dry Cask; Revision 0
- 72.48-3614; TN-40 Cask Removal and Storage Procedure; Revision 0
- 72.48-3634; D95.3 TCR 16A; Revision 0
- 72.48-3635; D95.3 TCR 16C; Revision 0
- 72.48-3782; ISFSI License Renewal Cask Baseline Inspection Activities; Revision 0
- 72.48-3830; SP 1076 – Changes Needed to Support ISFSI LRA; Revision 0
- Altran Solutions Report 12-1297-TR-001; Laboratory Evaluation of Two EDG Pressure Switches; Revision 0
- CAP 1230185; NSAL 04-07 Response Requires Re-Evaluation; April 30, 2010
- CAP 1256477; Aux Building Crane Overload Torque Value not in Required Range; October 29, 2010
- CAP 1259086; D95.3 Revision 16 Does Not Account for Meter Accuracy; dated November 17, 2010
- CAP 1261221; Cask OP Port Drying Failure; December 2, 2010
- CAP 1261300; Cask 28 Delay in Completing D95.3; December 3, 2010

- CAP 1261773; Level of Use Designation of D95 Procedures May be Incorrect; December 6, 2010
- CAP 1262114; Vacuum Drying Pump #1 Discharge Hose Clogged; December 8, 2010
- CAP 1267759; Review Procedures for Changes Required by ISFSI TS Change; January 25, 2011
- CAP 1268155; ISFSI TS Bases Does Not Adequately Define Helium Environment; January 27, 2011
- CAP 1271682; Alpha Detection for ISFSI TS SR 3.2.1.1; February 18, 2011
- CAP 1286131; Inappropriate Assumption in TN-40 Cavity Pressure Calculation; May 16, 2011
- CAP 1331493; Fabrication of Dry Cask is not in Accordance with the TS; May 29, 2012
- CAP 1343946; Various Temperature Limits Impacting Plant Operation; July 5, 2012
- CAP 1356782; 2012 Fukushima Flooding Walkdowns: Degraded Cap on Pipe; October 27,2012
- CAP 1356938; 2012 Fukushima: No Details on Penetrations Through Flood Wall; October 29, 2012
- CAP 1356972; 2012 Fukushima: Rodd Drain Piping with Victaulic Couplings; October 29, 2012
- CAP 1356975; 2012 Fukushima: Lack of Configuration for Penetrations; October 29, 2012
- CAP 1357039; 2012 Fukushima Flooding Walkdowns – AB-4 Suggestions; October 30, 2012
- CAP 1357431; 2012 Fukushima: Configuration of Conduit Ends in Screenhouse; November 1, 2012
- CAP 1357449; 2012 Fukushima: D5-D6 Cannot Verify Internal Seal in Conduit; November 1, 2012
- CAP 1357457; 2012 Fukushima: Cracked Penetration Seal on Cooling Water Dump to Grade; November 1, 2012
- CAP 1357903; 2012 Fukushima: External Flood Wall Physical Margin; November 5, 2012
- CAP 1365269; D1/D2 Room Temperature Issue not Addressed by Summer Readiness; January 3, 2013
- CAP 1365269; July D1/D2 Lube Oil Switch Replacement/OPR Strategy; January 3, 2013
- CTL Group Report Summarizing Test Results From Unit 2 Concrete Samples From The Prairie Island Nuclear Generating Plant Project 403966; October 30, 2012
- D58; Heavy Loads Program; Revision 33
- D95.1 TN-40 Cask Loading Procedure; Revision 18
- D95.2 TN-40 Cask Unloading Procedure; Revision 13
- D95.3 TN-40 Cask Removal and Storage Procedure; Revision 20
- D95.4 TN-40 Cask Receipt Procedure; Revision 22
- Engineering Change 21014; Past Operability for Heat-up Analysis for D1/D2 for Revised Outside Air Temperature Limit; Revision 0
- H24.3; Structures Monitoring Program; Revision 8
- H24; Maintenance Rule Program; Revision 17
- Maintenance Rule Evaluations 1347349-02 through -05; September 28, 2012
- NOS Observation 2011-03-010; In-Service Testing and Independent Spent Fuel Storage Installation; September 22, 2011
- NOS Observation 2012-03-004; ISFSI; August 1, 2012
- NOS Observations 2010-04-015; Independent Spent Fuel Storage Installation; December 10, 2010
- OPR 1166457; Containment Isolation Sump ‘B’ Valves Voids, Operability Evaluation; Revision 0
- PING 196; Turbine Building Data – Unit 2; Revision 117

- Planning and Approval of High Risk or Scheduled Risk Work; Dry Cask #27, 28, 29 Load and Storage at ISFSI
- SP 1075.HT; TN-40HT Fuel Selection and Identification; Revision 1
- SP 1075; TN-40 Fuel Selection and Identification; Revision 13
- SP 1293; Inspection of Flood Control Measures; Revision 22
- Trunnion Load Testing Report- Cask 34; September 25, 2011
- WO 00342224-01; PM 3586-10 Quarterly Periodic Structures Inspection; June 29, 2008
- WO 00405593-01; SP 1077 Special Lift Fixture for TN-40 Cask
- WO 00416740-01; SP 1075 TN-40 Fuel Selection and Identification; November 19, 2010

4OA7 Licensee Identified Findings

- CAP 1356385; Control Valve 31999 – 22 Turbine Driven Auxiliary Feedwater Pump Main Steam Supply Timed Too Slow; October 25, 2012
- CAP 1357566; NUE HU4.1 Declared 10/31/12 Event Response; November 2, 2012
- CAP 1357663; Security NUE Classification; November 2, 2012
- CAP 1357722; NUE Response – Event Response not Formally Initiated by Station Duty Manager; November 3, 2012
- CAP 1357723; NUE Response – Control Room Layout Issues; November 3, 2012
- CAP 1357789; Stop Work – Repeat Augmented Quality Door Part not Traceable; November 4, 2012
- Causal Evaluation 1345525; Concrete Pipe Trench Cover Removed in D5/D6 Building; October 5, 2012
- Human Performance Event Review for Notice of Unusual Event; November 1, 2012

LIST OF ACRONYMS USED

°F	Degrees Fahrenheit
ΔCDF	Change in Core Damage Frequency
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
BA	Boric Acid
BACC	Boric Acid Corrosion Control
BWR	Boiling-Water Reactor
CAP	Corrective Action Program
CE	Condition Evaluation
CLB	Current Licensing Basis
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
CS	Containment Spray
DDCLP	Diesel Driven Cooling Water Pump
DDFP	Diesel Driven Fire Pump
DID	Defense in Depth
DRP	Division of Reactor Projects
DNMS	Division of Nuclear Materials Safety
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPD	Electronic Personal Dosimeter
EPIP	Emergency Plan Implementing Procedures
EPRI	Electric Power Research Institute
ET	Eddy Current Testing
FCU	Fan Control Unit
GL	Generic Letter
HELB	High Energy Line Break
HRA	High Radiation Area
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Facility Installation
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LR	License Renewal
LOOP	Loss of Off-site Power
Mbar	Millibar
MCID	Materials Control, ISFSI, and Decommissioning
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NOUE	Notice of Unusual Event
NRC	U.S. Nuclear Regulatory Commission

NRR	Office of Nuclear Reactor Regulation
OM	Operations and Maintenance
OOS	Out of Service
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PI	Performance Indicator
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
PMCR	Preventive Maintenance Change Request
PT	Dye Penetrant Test
PWR	Pressurized-Water Reactor
RFO	Refueling Outage
RHR	Residual Heat Removal
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
SRA	Senior Reactor Analyst
SRO	Senior Reactor Operator
SSC	Systems, Structures, and Components
TDAFW	Turbine Driven Auxiliary Feedwater
TI	Temporary Instruction
TS	Technical Specification
USAR	Updated Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Examination
VT	Visual Examination
WO	Work Order

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Sincerely,

/RA/

Kenneth Riemer, Chief
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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