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

January 31, 2011

Mr. Mark A. Schimmel
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 05000282/2010005; 05000306/2010005 AND INSPECTION OF MEASUREMENT UNCERTAINTY RECAPTURE POWER UPRATE ACTIVITIES

Dear Mr. Schimmel:

On December 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The NRC also completed inspection activities associated with your implementation of a measurement uncertainty recapture power uprate on both units. The enclosed report documents the results of these inspections, which were discussed on January 13, 2011, 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 and two self-revealed findings of very low safety significance were identified. Each finding 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.

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, 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 document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000282/2010005; 05000306/2010005
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:	05000282/2010005; 05000306/2010005
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, 2010
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector C. Brown, Reactor Inspector J. Dalzell-Bishop, Reactor Engineer L. Kozak, Senior Reactor Analyst R. Lerch, Project Engineer D. McNeil, Senior Operations Engineer
Approved by:	John B. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000282/2010005, 05000306/2010005; 10/01/2010 – 12/31/2010; Prairie Island Nuclear Generating Plant, Units 1 and 2; Operability Evaluations, Event Follow-up and Other Activities.

This report covers a 3-month period of inspection by resident inspectors and an inspection of activities associated with a measurement uncertainty recapture power uprate on both units. Seven Green findings were identified by the inspectors. Each of these findings was considered a non-cited violation (NCV) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. In July 2010, the inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion III, due to the failure to establish measures to assure that the design of the 12 battery charger was verified using a suitable testing program. Specifically, the test program did not ensure that the 12 battery charger would operate as required during a loss of offsite power event coincident with a loss of coolant accident (LOOP/LOCA event). Corrective actions for this issue included establishing a designated operator to ensure that actions could be taken to reset the 12 battery charger if needed following a LOOP/LOCA event. This designated operator will remain in place until the licensee modifies the 12 battery charger during the next Unit 1 refueling outage.

  The inspectors determined that this issue was more than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone. In addition, this deficiency impacted that cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors completed Phase 1 and Phase 2 SDP evaluations, and determined that a Phase 3 SDP evaluation was required due to this issue being potentially greater than green. The Region III Senior Reactor Analyst (SRA) completed the Phase 3 evaluation and determined that this finding was of very low safety significance due to the low probability of a LOOP/LOCA event and because the licensee had procedural guidance in place to restore the 12 battery charger if required. No cross-cutting aspect was assigned to this finding since the cause of the finding was not reflective of current performance. (Section 1R15.1.b(1))

- Green. The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, in October 2010, due to the failure to complete an adequate immediate and prompt operability determination on the D2 emergency diesel generator (EDG) and the 12 battery charger in accordance with Procedure FP-OP-OL-01, "Operability/Functionality Determination." Corrective actions for this issue included revising the respective operability evaluations to comply with procedural requirements, providing additional training on the operability process to

operations and engineering personnel, and implementing a daily management review of operability decisions.

The inspectors determined that the finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone. In addition, this finding impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors completed the Phase 1 and Phase 2 SDP evaluations, and determined that a Phase 3 SDP evaluation was required because the finding was potentially greater than green. The SRA performed a Phase 3 SDP evaluation and determined that this finding was of very low safety significance due to the low probability of a LOOP/LOCA event and because the licensee had procedural guidance in place to restore the 12 battery charger if required. This finding was determined to be cross-cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee had not taken appropriate corrective actions to address a previously identified adverse trend regarding the adequacy of operability determinations (P.1(d)). (Section 1R15.1.b(2))

- Green. The inspectors identified a finding of very low safety significance and an NCV of Technical Specification (TS) 3.8.1 in October 2010 due to the failure to demonstrate that the D2 EDG would energize the 12 battery charger within 60 seconds of an actual or simulated LOOP/LOCA event. Specifically, the licensee failed to comply with TS surveillance requirement 3.8.1.10c. Corrective actions for this issue included declaring the D2 EDG inoperable; requesting an exigent TS change from the NRC to address the issues associated with TS Surveillance Requirement 3.8.1.10c; receiving approval of the exigent TS change; and implementing actions to address a long-standing issue with the 12 battery charger.

  The inspectors determined that this issue was more than minor because, if left uncorrected, long-standing noncompliance with TS requirements would become a more significant safety concern. The inspectors completed a Phase 1 SDP evaluation and determined that this finding was of very low safety significance because it was not due to an EDG design deficiency; did not result in a loss of safety function for the Unit 1 EDGs; and did not screen as potentially risk significant due to a seismic, flooding or severe weather initiating event. No cross-cutting aspect was assigned to this finding because the decisions which led to the non-compliance were made several years ago and were not reflective of current performance. (Section 1R15.1.b(3))

- Green. The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, on November 12, 2010, due to the failure to complete an immediate operability determination for the D5 EDG in accordance with Procedure FP-OP-OL-01, “Operability/Functionality Determination.” Specifically, operations personnel failed to properly assess the impact of a malfunctioning fuel oil transfer system on the ability of the D5 EDG to perform its safety function as required by the procedure. Corrective actions for this issue included declaring the D5 EDG inoperable; repairing the fuel oil transfer system equipment deficiency; satisfactorily testing the D5 EDG following the equipment repairs; providing additional training on the operability process to operations personnel; and implementing a daily management review of operability decisions.

The inspectors determined that this issue was more than minor because it was associated with the human performance, procedure quality, and configuration control attributes of the Mitigating Systems Cornerstone. This finding also impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance because, although this potential design deficiency resulted in a loss of D5 EDG operability, it did not result in D5 inoperability for greater than TS allowed time, did not result in a loss of safety function for the Unit 2 EDGs and it did not screen as potentially risk significant due to a seismic, flooding or severe weather initiating event. The inspectors concluded that this finding was cross-cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee had not taken appropriate corrective actions to address a previously identified adverse trend regarding the adequacy of operability determinations (P.1(d)). (Section 1R15.1)

- Green. A self-revealed finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion IV, was identified on July 25, 2010, due to the licensee's failure to specify the required 121 motor driven cooling water pump shaft coupling hardness as part of the procurement process. As a result, the pump was rendered unavailable due to a shaft coupling failure due to excessive hardness of the shaft. Corrective actions for this issue included repairing the cooling water pump and revising the procurement documents to include the required coupling hardness.

  The inspectors determined that this issue was more than minor because it impacted the design control attribute of the Mitigating Systems Cornerstone. This finding also impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors completed the Phase 1 and Phase 2 SDP evaluations and determined that a Phase 3 evaluation was required due to this issue being potentially greater than green. The Region III SRA determined that this finding was of very low safety significance because it did not represent an increase in the likelihood of a loss of cooling water initiating event due to different couplings being installed on the other cooling water pumps. The inspectors determined that this finding was cross-cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee did not use operating experience to support plant safety. Specifically, the licensee did not implement changes to the 121 motor driven cooling water pump after receiving and reviewing multiple pieces of operating experience regarding coupling failures due to hardness issues (P.2(b)). (Section 4OA3.1)

- Green. A self-revealed finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, was identified on November 12, 2010, due to the failure to follow procedure while transferring the power supply for motor control center 1T1 from Unit 1 to Unit 2. The failure to follow procedures resulted in removing safety-related radiation monitor 1R11/1R12 from service and an unplanned entry into TS 3.4.16.B. Corrective actions for this issue included returning radiation monitor 1R11/1R12 to service and re-enforcing the use of human performance tools to operations personnel.

  The inspectors determined that this issue was more than minor because, if left uncorrected, the performance of plant activities on the incorrect unit would become a more significant safety concern. The inspectors concluded that this finding was of very

low safety significance because the removal of the radiation monitor from service was not a design deficiency; did not result in a loss of system safety function for greater than the TS allowed outage time; and was not potentially risk significance due to seismic, flooding or severe weather initiating events. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because personnel failed to use human error prevention techniques to ensure that work was performed safely (H.4(a)). (Section 4OA5.1)

Cornerstone: Barrier Integrity

- Green. The inspectors identified finding of very low safety significance and an NCV of 10 CFR 50.65 a(4) on August 31, 2010, due to a failure to properly assess and manage the risk associated with performing planned maintenance activities on the 111 switchgear unit cooler and the 121 control room chiller. Specifically, the licensee failed to identify these maintenance activities as high risk and implement additional risk management actions prior to starting the maintenance. As a result, an unexpected low suction pressure condition occurred on the 122 control room chiller pump. Corrective actions included restoring from the maintenance activities.

  The inspectors determined the finding was more than minor because if left uncorrected, the failure to properly assess and manage plant risk could result in the need to shut down both reactors (a more significant safety concern) due to a loss of control room cooling function. This finding was determined to be of very low safety significance because it was not specific to the radiological barrier provided by the control room ventilation system; was not a degradation of the barrier function of the control room against smoke or a toxic atmosphere; did not represent an actual open pathway in the reactor containment; and it did not involve an actual reduction in the function of hydrogen igniters. The inspectors concluded that this finding was cross-cutting in the area of Human Performance, Work Control area because the licensee did not plan and coordinate work activities consistent with nuclear safety (H.3(a)). (Section 4OA5.2)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating near 100 percent power. On October 15, 2010, licensee personnel implemented a measurement uncertainty recapture (MUR) power uprate which allowed a 1.64 percent increase in reactor power. Unit 1 operated at this new full power level with the following exceptions:

- At approximately 5:00 a.m. on November 4, 2010, operations personnel were required to lower reactor power to 95 percent due to an unexpected failure of the 11 heater drain tank pump speed control system;
- At approximately 8:00 p.m. on November 4, 2010, operations personnel lowered reactor power to approximately 45 percent to perform required turbine valve testing and to clean the condenser. Operations personnel restored Unit 1 to full power on November 6, 2010; and
- On December 9, 2010, operations personnel lowered reactor power to approximately 98 percent to perform planned maintenance on the 11 and 12 heater drain tank pumps.

Unit 2 also began the inspection period operating near 100 percent power. On October 9, 2010, licensee personnel implemented an MUR power uprate which allowed a 1.64 percent increase in reactor power. Unit 2 operated at or near this new full power level with the following exceptions:

- On October 29, 2010, operations personnel lowered Unit 2 power to 45 percent to perform required turbine valve testing. Operations personnel restored Unit 2 to full power on October 30, 2010;
- On December 17, 2010, operations personnel lowered Unit 2 power to 98 percent to return the 23 heater drain tank pump to service; and
- On December 31, 2010, operations personnel lowered Unit 2 power to 95 percent due to 23 heater drain tank pump speed control issues.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and the licensee's implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for the selected systems was reviewed to ensure that the systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the procedures used to mitigate

or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Safety Analysis Report (USAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with procedures. Specific documents reviewed during this inspection are listed in the Attachment. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- Screenhouse Normal Ventilation, and
- Screenhouse Safeguards Ventilation.

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- 11 Turbine Driven Auxiliary Feedwater Pump, and
- Emergency Diesel Generators D5 and D6.

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

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

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On December 9, 2010, the inspectors performed a complete system alignment inspection of the screenhouse normal and safeguards ventilation 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 line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed 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 of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Battery Rooms 11 & 12 (Fire Zone 1);
- Battery Rooms 21 & 22 (Fire Zone 35);
- 480V Safeguards Switchgear Bus 111 & 121 Room (Fire Zone 43); and
- 480V Safeguards Switchgear Bus 122 & Train "B" Event Monitoring Room (Fire Zone 50).

The inspectors reviewed the areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within

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

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

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On November 17, 2010, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with procedures. The inspectors evaluated the following areas:

- operator performance;
- clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors;
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications; and
- simulator control board indications and procedures had been updated to reflect reactor operations following the MUR power uprate implementation.

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

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

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results (71111.11B)

a. Inspection Scope

The inspector reviewed the overall pass/fail results of the individual Job Performance Measure operating tests, and the simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from September 20, 2010, through October 29, 2010, as part of the licensee's operator licensing requalification cycle. These results were compared to the thresholds established in Inspection Manual Chapter 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process (SDP)." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG 1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The documents reviewed during this inspection are listed in the Attachment.

Completion of this section constituted one biennial licensed operator requalification inspection sample as defined in IP 71111.11B.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- 12 Diesel Driven Cooling Water Pump;
- 22 Diesel Driven Cooling Water Pump;
- 121 Motor Driven Cooling Water Pump; and
- Diesel Fuel Oil System.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;

- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

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

b. Findings

No findings of significance were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- D2 Emergency Diesel Generator Inoperable Coincident with a Red Channel Over Pressure Delta Temperature Instrument Failure;
- Severe Weather Coincident with Maintenance on Transformer 1RYBT; and
- Planned Maintenance during the week of November 8, 2010.

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 three samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Operability Recommendation (OPR) 1238842-01, Revisions 0 and 1; Operability of D2 and 12 Battery Charger due to Incomplete Performance of Surveillance Procedure (SP) 1083;
- CAP 1250561 and OPR 1250561-02; Safety Related Battery Chargers May Lock Up During Specific Design Basis Events; and
- OPR 1257627; D5 Fuel Oil Day Tank Auto Level Control Problems.

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

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

b. Findings

Findings Associated with Operability Recommendation 1238842-01

Introduction: The inspectors identified three findings of very low safety significance with associated NCVs of NRC requirements. The findings were as follows:

- Failure to perform appropriate post-modification testing following the installation of the 12 battery charger;
- Failure to properly implement procedural instructions during the completion of the immediate and prompt operability evaluations for the D2 emergency diesel generator (EDG) and the 12 battery charger; and
- Noncompliance with TS Surveillance Requirement (SR) 3.8.1.10c due to historical procedure changes and inappropriate application of TS SR 3.0.3.

Description: Technical Specification SR 3.8.1.10c requires the licensee to demonstrate that each EDG automatically starts from a standby condition and energizes all emergency loads within 60 seconds of experiencing an actual or simulated loss of offsite power signal in conjunction with an actual or simulated safety injection actuation signal (hereafter referred to as a LOOP/LOCA event) every 24 months. Surveillance Procedure 1083 was one of the procedures the licensee used to demonstrate compliance with this TS SR.

In December 1994, the licensee replaced all four safety-related battery chargers. Prior to installation, the licensee developed a test plan for the chargers. The purpose of the test plan was to ensure that the chargers would perform their safety function under all required conditions. The charger manufacturer implemented and completed the test plan prior to the chargers leaving the factory. However, the test plan did not verify that the chargers would operate as required following a real or simulated LOOP/LOCA event. When SP 1083 was performed in February 1996, the 12 battery charger failed to operate as expected. Specifically, the battery charger was initially supplied power from the EDG within the 60 seconds. However, as other safety-related loads continued to sequence onto the EDG, the 12 battery charger experienced a low voltage condition, which resulted in the charger failing to provide any output voltage until it was manually reset by a non-licensed operator. The licensee conducted troubleshooting activities and dispositioned this issue as “use as is.” In addition, the licensee revised the battery charger abnormal operating procedures to address the failure of the battery charger to function as expected during a LOOP/LOCA event.

The next required performance of SP 1083 was completed on December 5, 1997. Again, the 12 battery charger failed to perform as expected. The licensee initiated Non-Conformance Report 19971622 to document the issue with the charger. This non-conformance report was also dispositioned as “use as is.”

Between January 1, 1999, and October 25, 2005, the licensee had multiple internal discussions regarding the failure of the 12 battery charger to operate as expected during the performance of SP 1083. On May 10, 1999, the licensee revised SP 1083 such that the 12 battery charger was turned off during the surveillance test. In 2002, the licensee proposed implementing a modification to correct the 12 battery charger issue. However, this modification was placed on hold in 2004 and subsequently cancelled on October 25, 2005, since the actions to address the battery charger issue had been proceduralized and the actions were viewed as an acceptable practice.

On October 23, 2009, a licensed operator initiated CAP 1203825 to document that the long-standing issues with the 12 battery charger failing to operate as expected during SP 1083 had not been corrected. The operator also stated that the use of proceduralized actions “was not indicative of having the right picture regarding safeguards equipment.” In response to this CAP, the licensee placed this issue on the operator workaround (OWA) list. The licensee also initiated actions to begin resurrecting the 2002 proposed modification.

On June 24, 2010, the licensee initiated CAP 1238842 to document several issues regarding SP 1083. The issues included the following:

- SP 1083 had been performed with a configuration that was different than what was intended (and what was required) since 1999;

- SP 1083 was changed in 1999 without completing the required 10 CFR 50.59 safety evaluation or screening; and
- The 12 battery charger would likely experience a lock up during an actual LOOP/LOCA event.

The operations shift manager completed an immediate operability determination and concluded that the 12 battery charger remained fully operable because procedures were in place to respond to a battery charger trip after a LOOP/LOCA event. In addition, the shift manager believed that he had reasonable assurance that adequate time existed to perform procedure steps to restore the 12 battery charger prior to the safety-related battery voltage degrading below the minimum acceptable level. The shift manager assigned a prompt operability determination to the engineering department and specifically requested that the use of manual actions to restore the 12 battery charger be evaluated per the requirements in 10 CFR 50.59. The continued operability of the D2 EDG was not addressed in the shift manager's immediate operability determination.

The shift manager approved OPR 1238842-01, Revision 0, on July 2, 2010. Within this operability determination operations and engineering personnel concluded that the 12 battery charger was operable but non-conforming due to the use of manual operator action to restart the charger following a LOOP/LOCA event. The D2 EDG was also determined to be operable but non-conforming due to the failure to demonstrate compliance with TS SR 3.8.1.10c. Lastly, the licensee documented that TS SR 3.0.3, which provides allowances to delay the performance of TS SRs that are missed, would be entered to address the noncompliance with TS SR 3.8.1.10c.

In July 2010, the NRC's Component Design Basis Inspection (CDBI) inspection team reviewed OPR 1238842-01 and the circumstances which led to the licensee revising SP 1083 in May 1999. During this inspection, the team became concerned that the licensee had not performed adequate post-modification testing following the installation of the new battery chargers in 1995. The licensee initiated CAP 1243574 in response to the inspectors' concerns. However, this issue was not dispositioned in the CDBI report due to additional concerns identified, and further information needed by the resident inspectors following the completion of the CDBI.

In September 2010, the licensee initiated CAP 1250561 to document that all four safety-related battery chargers may stop operating under certain conditions. Based upon the information included in this CAP, the resident inspectors performed a review of this CAP, CAPs 1243574 and 1238842, and OPR 1238842-01. The inspectors identified the following performance deficiencies:

- The licensee failed to perform adequate post-modification testing following installation of the 12 battery charger in 1994. Specifically, the licensee did not perform SP 1083 to ensure that the battery charger would perform as required following a LOOP/LOCA event;

- Operations and engineering personnel failed to implement the operability determination process as required by procedure. For example:

    - The shift manager failed to address the immediate operability of the D2 EDG following the initiation of CAP 1238842;

- The immediate operability determination for the 12 battery charger was based upon a “reasonable assurance” of operability. However, the basis for this reasonable assurance was not adequately documented to demonstrate that the 12 battery charger would continue to perform its safety function. For example, operations personnel believed that adequate time was available to reset the charger through the use of manual actions. However, no data existed to support this belief; and
- Operations and engineering personnel failed to adequately evaluate the use of manual operator actions in place of automatic actions as required by procedure. For example, no evaluation was provided to show that the manual actions could be taken under all design basis events.

- The licensee identified that they had inappropriately revised SP 1083 in 1999 to allow the 12 battery charger to be turned off prior to performing the test. As a result, the licensee had not been demonstrating full compliance with TS SR 3.8.1.10c. However, the inspectors identified that the licensee had incorrectly concluded that this noncompliance was a missed surveillance. Due to this incorrect conclusion, the licensee had not entered the TS required actions or requested an exigent TS change from the NRC to disposition the noncompliance.

(1) Failure to Perform Appropriate Post-Modification Testing

Analysis: The inspectors determined that the failure to perform adequate post-modification testing following the installation of the 12 battery charger was a performance deficiency that required an SDP evaluation. The inspectors determined that this issue did not meet the criteria for consideration as an old design issue (as provided in NRC Inspection Manual Chapter (IMC) 0305) because the issue was not identified by the licensee and because the issue should have been identified following the repeated inability to successfully complete SP 1083.

The inspectors determined that this issue was more than minor because it was associated with the design control attribute of the Mitigating Systems Cornerstone. In addition, this performance deficiency impacted that cornerstone objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors completed a Phase 1 SDP evaluation and determined that a Phase 2 evaluation was required because the 12 battery charger had experienced a loss of safety function for greater than the TS allowed outage time. The SDP Phase 2 evaluation was performed using the Risk-Informed Inspection Notebook pre-solved spreadsheet for Prairie Island Nuclear Generating Plant. The Phase 2 result was a finding that was potentially greater than green. The Region III Senior Reactor Analyst (SRA) determined that this result was conservative because it assumed the condition would occur for all initiating events rather than specifically during a LOOP/LOCA event.

The SRA performed an SDP Phase 3 evaluation for the failure of the 12 battery charger during a LOOP/LOCA design basis event. The SRA used the NRC Simplified Plant Analysis Risk (SPAR) Model, Revision 8.15, to perform the evaluation. The exposure period was assumed to be 1 year. The model was solved assuming that the battery charger would fail in response to any LOCA event. The delta core damage frequency (CDF) was then multiplied by the LOOP initiating event frequency of 3.59E-2/yr. The result was a change in core damage frequency of less than 1E-7/yr, which is a finding of very low safety significance (Green). The dominant sequence was a LOOP/LOCA,

failure of the 12 battery charger due to the voltage transient, which fails all train "B" safety equipment, and random failure of train "A" safety equipment. No cross-cutting aspect was assigned to this finding because the cause of this finding was not reflective of the licensee's current performance.

Enforcement: Criterion III, Design Control, of 10 CFR Part 50, Appendix B, states that design control measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures and instructions. In addition, these measures shall provide for verifying or checking the adequacy of design such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, on December 21, 1994, the licensee failed to establish design control measures to assure that applicable regulatory requirements were correctly translated into specifications, drawings, procedures and instructions related to replacing the 12 safety-related battery charger via Modification 94L453. In addition, the licensee failed to ensure that these measures provided for verifying or checking the adequacy of the design through the use of a suitable testing program. Because this violation was of very low safety significance and it was entered into your corrective action program as CAP 1243574, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000282/2010005-01; Failure to Perform Adequate Post Modification Testing Following Battery Charger Replacement). Corrective actions for this issue included ensuring that current procedures provide adequate guidance on post-modification testing; establishing a designated operator to perform manual actions to reset the 12 battery charger if required; and future implementation of a modification to ensure that the 12 battery charger will operate as expected following a LOOP/LOCA event.

(2) Failure to Implement Operability Determination Process as Required by Procedure

Analysis: The inspectors determined that the multiple examples of the failure to implement the operability determination process as required by Procedure FP-OP-OL-01, "Operability/Functionality Determination," Revision 8, was a performance deficiency requiring an evaluation using the SDP. The inspectors determined that this issue was more than minor because it impacted the equipment performance attribute of the Mitigating Systems Cornerstone. In addition, this finding impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors completed a Phase 1 SDP evaluation and concluded that a Phase 2 evaluation was needed because this finding had resulted in a loss of safety function for the 12 battery charger for greater than the TS allowed outage time. The SDP Phase 2 evaluation was performed using the Risk-Informed Inspection Notebook pre-solved spreadsheet for Prairie Island Nuclear Generating Plant. The Phase 2 result was a finding that was potentially greater than green. The Region III SRA determined that this result was conservative because it assumed the condition would exist for all initiating events rather than only during a LOOP/LOCA event.

The SRA performed an SDP Phase 3 evaluation of the failure of the 12 battery charger during a LOOP/LOCA design basis event. The SRA used the NRC SPAR Model, Revision 8.15, to perform the evaluation. The exposure period was assumed to be one

year. The model was solved assuming that the 12 battery charger would fail in response to any LOCA event. The delta core damage frequency was then multiplied by the LOOP initiating event frequency of 3.59E-2/yr. The result was a change in CDF of less than 1E-7/yr, which is a finding of very low safety significance (Green). The dominant sequence was a LOOP/LOCA, failure of the 12 battery charger due to the voltage transient, which fails all train "B" safety equipment, and random failure of train "A" safety equipment. The inspectors determined that this finding was cross-cutting in the Problem Identification and Resolution Corrective Action Program area because the licensee had not taken appropriate corrective actions to address a previously identified adverse trend regarding the adequacy of operability determinations (P.1(d)).

Enforcement: Criterion V, Instructions, procedures and Drawings, of 10 CFR Part 50, Appendix B, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstance. The licensee implemented the operability determination process (an activity affecting quality) using Procedure FP-OP-OL-01, "Operabilty/Functionality Determinations," Revision 8.

- Step 3.2.2 of FP-OP-OL-01 required the shift manager to make operability determinations for all conditions that involve equipment issues related to the ability of the SSC to perform its specified safety function. However, the shift manager's operability determination failed to include an assessment of continued D2 operability.
- Section 9.4 of FP-OP-OL-01 states that reasonable expectation can only be used in determining whether or not a condition exists. The inspectors found that the use of reasonable expectation in the operability determination was not appropriate because previous performances of SP 1083 clearly demonstrated that a deficient condition existed with the 12 battery charger.
- Step 9.2 states that engineering judgment should be applied when appropriate to reach conclusions using the reasonable expectation method. However, no engineering judgment was provided in the shift manager's operability determination.
- Lastly, Section 10.2 stated that a sound basis for engineering judgment needed to be documented. Since no engineering judgment was provided, a sound basis was not provided.

Contrary to the above, on July 2, 2010, the licensee failed to complete the immediate operability for CAP 1238842 and OPR 1238842-01, Revision 0, as directed by Steps 3.2.2 and 9.2, and Sections 9.4 and 10.2 of Procedure FP-OP-OL-01. Because this violation was of very low safety significance and it was entered into your corrective action program as CAP 1253478, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000282/2010005-02; Failure to Complete Operability Determinations in accordance with Procedural Requirements). Corrective actions for this issue included revising OPR 1238842-01; completing additional management reviews of operability decisions; establishing an independent review group to ensure that technical documents contained appropriate detail and were technically adequate; and providing additional training to operations and engineering personnel on the operability determination process.

(3) Violation of Technical Specification 3.8.1

As discussed above, the licensee revised SP 1083 to direct removing the 12 battery charger from service prior to performing the surveillance test. Upon identifying that SP 1083 had been changed inappropriately, the licensee invoked the guidance provided in TS SR 3.0.3 for missed surveillances. Surveillance Requirement 3.0.3 states:

> "If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the Limiting Condition for Operation (LCO) not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance."

In addition, SR 3.0.3 states:

> "When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Conditions must be entered."

The TS Bases Section for SR 3.0.3 stated:

> "The basis for the delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements."

Based upon the information provided above, the inspectors were concerned that the licensee was not appropriately applying SR 3.0.3 for the following reasons:

- Based upon the licensee's previous surveillance test results, the most probable result of SP 1083 (performed with the 12 battery charger turned on) would be a test failure. Based upon this information, it appeared that the licensee should have declared TS LCO 3.8.1.b for the D2 EDG not met and entered the applicable conditions;
- SR 3.0.3 was to be used for surveillances that were missed rather than for surveillances that had never been performed.

The licensee initiated CAP 1253478 to document the inspectors' concerns. The inspectors also asked whether the licensee planned to perform SP 1083 twice during the next Unit 1 refueling outage. The licensee informed the inspectors that they had planned to perform SP 1083 after modifying the 12 battery charger. The inspectors then informed the licensee that SP 1083 was required to be performed prior to any modification to demonstrate that TS SR 3.8.1.10c was met under all conditions.

The inspectors also conferred with experts within the NRC's Office of Nuclear Reactor Regulation (NRR) regarding the licensee's application of TS SR 3.0.3. Following discussions with NRR, the inspectors provided the licensee with operating experience from another nuclear facility regarding the application of TS SR 3.0.3 to surveillances that had never been performed. Within this operating experience, the NRC had concluded (based upon information contained in that facility's TS) that TS SR 3.0.3 could

not be applied if a TS SR had never been performed. The inspectors found that the Prairie Island TS contained the same wording. The licensee reviewed this information, and the concerns documented in CAP 1253478, and declared the D2 EDG inoperable due to the failure to adequately demonstrate compliance with TS SR 3.8.1.10c. The licensee also submitted an exigent TS change to the NRC to allow Unit 1 continued operation until the next refueling outage. The NRC approved the exigent TS change on October 22, 2010.

Analysis: The inspectors determined that the failure to adequately implement TS SR 3.8.1.10c and TS SR 3.0.3 was a performance deficiency that required an SDP evaluation. This finding impacted the Mitigating Systems Cornerstone. The inspectors determined that this finding was more than minor because, if left uncorrected, the incorrect application of TS could become a more significant safety concern. The inspectors completed a Phase 1 SDP evaluation and determined that this finding was of very low safety significance because it was not an EDG design deficiency; did not result in a loss of system safety function for the Unit 1 EDGs; and was not potentially risk significant due to a seismic, flooding or severe weather initiating event. No cross-cutting aspect was assigned to this finding because the decision making which caused the long-term non-compliance was made several years ago and was not reflective of current performance.

Enforcement: Technical Specification SR 3.8.1.10c requires that the licensee verify that each EDG auto-starts from a standby condition and energizes emergency loads in less than or equal to 60 seconds following an actual or simulated loss of offsite power signal in conjunction with an actual or simulated safety injection signal. This test was required to be performed every 24 months. Technical Specification SR 3.0.1 requires failure to meet a surveillance as failure to meet the LCO.

Technical Specification 3.8.1.b requires two EDGs to be operable during Modes 1, 2, 3 and 4. Action F, for the condition of one EDG inoperable for greater than the time allowed in Action B, requires the plant to be in Mode 3 in 6 hours.

Contrary to the above, between May 10, 1999, and October 22, 2010, the licensee failed to verify that the D2 EDG auto-started from a standby condition and energized emergency loads (including the 12 battery charger) in less than or equal to 60 seconds following an actual or simulated loss of offsite power signal in conjunction with an actual or simulated safety injection signal; and the plant was not placed in Mode 3 within the required Action times. Specifically, on May 10, 1999, the licensee revised Procedure SP 1083 to remove the 12 battery charger from service such that this emergency load was unable to be energized by the D2 EDG following a simulated loss of offsite power signal in conjunction with a simulated safety injection signal. In addition, no actual events of this type have occurred to demonstrate compliance with this TS SR.

Because this violation was of very low safety significance, and it was entered into your corrective action program as CAP 1254673, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000282/2010005-03; Failure to Ensure Compliance with TS SR 3.8.1.10c). Corrective actions for this issue included providing training to appropriate personnel on the use and application of TS SR 3.0.3, submitting an exigent TS change to the NRC for review and approval, improving the operability determination process through the use of additional management review and feedback, and modifying the 12 battery charger.

Findings Associated with Operability Recommendation 1257627

Introduction: The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, due to the failure to properly complete an operability determination in accordance with approved procedures on the D5 EDG and its fuel oil transfer system after experiencing difficulties during surveillance testing. The failure to properly complete the operability determination led to operations personnel making an incorrect decision regarding the continued operability of the D5 EDG and its fuel oil transfer system.

Description: During a routine review of corrective action documents, the inspectors noted that operations personnel had experienced fuel oil day tank level control problems during the monthly run of the D5 EDG. The corrective action document also contained information regarding the potential use of manual operator actions during the surveillance test. Based upon issues identified in previous OPRs, the inspectors selected this CAP for additional inspection.

The inspectors reviewed the control room operator logs and found that SP 2093, "D5 Diesel Generator Monthly Slow Start Test," was performed on November 8, 2010. Approximately 45 minutes after starting the SP, operations personnel received a control room alarm indicating a potential problem with the D5 EDG. A non-licensed operator (NLO) responded to the D5 room and identified that the D5 day tank fuel oil volume was very high and that the 21 fuel oil transfer pump (FOTP) was cycling on at 98 percent day tank level and cycling off at 100 percent day tank level. The NLO was directed to place the 23 FOTP in the preferred position. The 23 FOTP exhibited the same cycling behavior. The NLO was directed to complete the SP with the 23 FOTP in the off position and the 21 FOTP in auto while manually maintaining a day tank level band of 73 to 90 percent. Once the SP was completed, the FOTPs were placed in their normal configuration.

The inspectors reviewed the shift manager's immediate operability determination and found that he had declared the D5 EDG fully operable based upon the belief that the performance of the FOTPs would not adversely affect D5 EDG operability. The inspectors reviewed licensing and design basis documents and found that each one required the fuel oil transfer system to automatically provide fuel oil to the EDG. The inspectors also found that operations personnel had failed to consider the use of manual operator actions, or the potential for EDG failure due to FOTP failure, when determining the ability of the D5 EDG to perform its safety function for the specified mission time. Based upon this information, the inspectors were concerned that the licensee had inappropriately declared the D5 EDG operable following the completion of SP 2093.

The inspectors provided the above information to the licensee on November 12, 2010. Following a review of the inspectors' concerns, and finding generic information that the FOTPs could fail due to cycling, the licensee declared the D5 EDG inoperable.

Analysis: The inspectors determined that the failure to appropriately complete an operability determination following the discovery of a D5 fuel oil transfer system malfunction was a performance deficiency that required evaluation using the SDP. This issue impacted the Mitigating Systems Cornerstone. The inspectors determined that this issue was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone. In addition, this finding

impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that this finding was of very low safety significance because it was not a design deficiency; it did not result in a loss of safety function for the D5 EDG for greater than the TS allowed outage time; and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. The inspectors concluded that this finding was cross-cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee had not taken appropriate corrective actions to address a previously identified adverse trend regarding the adequacy of operability determinations (P.1(d)).

Enforcement: Criterion V to 10 CFR Part 50, Appendix B, requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstance. The licensee implemented the operability determination process (an activity affecting quality) using Procedure FP-OP-OL-01, "Operability/Functionality Determinations." Step 5.3.1.3 of FP-OP-OL-01 stated that an operability determination shall be sufficient to address the capability of the SSC to perform its specified safety function.

Contrary to the above, on November 8, 2010, operations personnel performed an operability determination on CAP 1257627, which was not sufficient to address the capability of the D5 EDG to perform its specified safety function. Specifically, the operability determination failed to address the use of manual operator actions or the impact of fuel oil transfer pump motor cycling on the ability of the D5 EDG to perform its safety function for the required mission time. Because this violation was of very low safety significance, and it was entered into your corrective action program as CAP 1257627, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000306/2010005-04; Failure to Appropriately Complete an Operability Determination on D5 EDG). Corrective actions for this issue included replacing the fuel oil day tank auto level control switch; returning the D5 EDG to service; providing additional operability determination training to operations personnel; and implementing a daily management review of operability decisions.

Review of Corrective Action Program 1250561 and Operability Recommendation 1250561-02

Introduction: An unresolved item (URI) was identified due to the potential for all safety-related battery chargers to lock up during specific design basis events.

Description: On September 21, 2010, the licensee initiated CAP 1250561 to document that a grid disturbance of sufficient voltage and time duration could cause all of the safety-related battery chargers to lock up until the chargers were manually turned off and restarted. While the CAP stated that this type of event was unlikely, the exact grid voltage and time required to cause the chargers to cease to operate was unknown. The CAP also stated that based upon recent battery discharge test results, operations personnel would have at least 2 hours and 20 minutes to restart the battery chargers.

The licensee's corrective action screening team reviewed CAP 1250561 on September 28, 2010. The screening team recommended that the Engineering Department review previous testing data and the apparent cause report for

CAP 1238842 (discussed above) to determine if additional actions were needed. This review was required to be completed by October 29, 2010.

On October 8, 2010, the NRC participated in a conference call to discuss issues related to the 12 battery charger (discussed above) and the licensee's evaluation of CAP 1250561. During this call, the licensee stated that CAP 1250561 was continuing to be evaluated. As a result, no additional actions had been taken.

On October 15, 2010, the NRC formally asked the licensee to address the potential for a common mode failure of all of the safety-related battery chargers as part of a request for information to support the exigent TS change to TS SR 3.8.1.10c. The inspectors reviewed the licensee's formal response to the NRC and the evaluation of the condition contained in CAP 1250561. The CAP evaluation contained information which indicated that each of the safety-related battery chargers may be susceptible to a lock up condition during specific design basis events including a loss of offsite power and a loss of coolant event with the grid voltage above operability limits. The licensee established a designated operator to perform manual actions to address the potential battery charger lock up condition to ensure there is no current safety concern. The licensee was continuing to evaluate this condition at the conclusion of the inspection period. As a result, this item was considered unresolved until the NRC reviews the results of the licensee's completed evaluation (URI 05000282/2010005-05; 05000306/2010005-05; Potential for Common Mode Failure of Safety-Related Battery Chargers).

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- Engineering Change 16614, Revision 1 – Portable Air Compressor in the Intake Screenhouse.

The inspectors compared the temporary configuration change and associated 10 CFR 50.59 screening and evaluation information 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 also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modification was installed as directed; the modification operated as expected; 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. Lastly, the inspectors discussed the temporary modification with operations and engineering personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one temporary modification sample as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 11 Heater Drain Tank Pump following planned maintenance;
- Bus 16 Load Sequencer testing following emergent maintenance; and
- 23 Charging Pump following planned maintenance.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TS, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed 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 of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- SP 1093 – D1 Monthly Slow Start (routine);
- SP 1094 – Bus 15 Load Sequencer (routine);
- SP 2093 – D5 Monthly Slow Start (routine);
- SP 1245A/B – 11/13 & 12/14 Fan Coil Unit ZX Valves Stroke Quarterly Test (inservice test); and
- SP 2001 AA – Reactor Coolant System (RCS) Leakage Test (RCS leakage).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; 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.

This inspection constituted three routine surveillance testing samples, one inservice testing sample, and one RCS leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance 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 (RHR) System performance indicator (PI) for Unit 1 and 2 for the period from the fourth quarter of 2009 through the third quarter of 2010. 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, were used. The inspectors reviewed the licensee's operator narrative logs, CAPs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period provided above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI RHR system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for Unit 1 and 2 for the period from the fourth quarter of 2009 through the third quarter of 2010. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, CAPs, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period provided 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 cooling water system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

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

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold; that adequate attention was being given to timely corrective actions; and that adverse trends were identified and addressed. Attributes reviewed included: 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

One finding of very low safety significance is documented in Section 1R15.1 of this inspection report.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings of significance were identified.

.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 period of June 1, 2010, through December 6, 2010, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings of significance were identified.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of the process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one OWA annual inspection sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.5 Selected Issue Follow-Up Inspection: CAP 1223694 – Safeguards Bus Load Sequencer Programmable Logic Controllers

a. Inspection Scope

On March 22, 2010, a licensee individual initiated CAP 1223694 to document concerns regarding the status of the safeguards bus load sequencers. The load sequencers are programmable logic controllers (PLCs) used to ensure that safety-related loads sequence onto the EDGs during a loss of normal alternating current to the plant. The CAP contained information that previous corrective actions involving the installation of a diagnostic laptop computer may have resulted in masking load sequencer test failures. The inspectors discussed this issue with the licensee individual, and personnel from the operations, engineering and nuclear oversight departments. The inspectors reviewed vendor technical manual information to determine the method to be used to test and troubleshoot the load sequencer. This method was then compared to the steps provided

in the licensee's test procedure. The inspectors also reviewed load sequencer test data acquired since December 20, 2007.

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

b. Observations and Findings

On December 21, 2007, licensee personnel were required to shut down Prairie Island Unit 1 due to the inoperability of both EDGs. Specifically, the D2 EDG had been taken out of service for routine maintenance. This required the licensee to test the load sequencer associated with the D1 EDG to ensure it remained operable. During this test, the Bus 15 (D1 EDG) load sequencer was declared inoperable due to receiving multiple error code 103 signals during the test. This issue was reported to the NRC as Licensee Event Report (LER) 05000282/2007-004. The licensee determined that the Bus 15 load sequencer failed due to age related degradation of the input/output cards. Proposed corrective actions included the replacement of the input/output cards on all of the load sequencers; the development of an appropriate preventive maintenance strategy for the load sequencers and their subcomponents; and the development of a spare parts list for the load sequencers and their subcomponents.

In June 2008, the inspectors reviewed a portion of the corrective actions associated with the December 2007 shut down. As documented in NRC Inspection Report 05000282/2008004; 05000306/2008004, the inspectors identified an NCV of NRC requirements because the licensee had changed the load sequencer surveillance procedures such that the acceptance criteria associated with receiving the error code 103 signal were non-conservative and in conflict with the vendor manual. On June 12, 2008, the licensee revised the surveillance procedure acceptance criteria so that it no longer conflicted with the vendor manual.

On September 30, 2008, the Bus 15 load sequencer failed its monthly surveillance test due to receiving multiple error code 103 signals (CAP 1152949). The licensee installed a laptop computer to aid in diagnosing the load sequencer failure via a temporary procedure change. The licensee performed the surveillance test 20 additional times and was unable to recreate the error signal. The licensee concluded that the error signals were spurious (as discussed in the vendor manual) and returned the Bus 15 load sequencer to service. The licensee also initiated actions to revise the load sequencer surveillance procedures such that the diagnostic laptop was installed prior to performing surveillance testing.

The surveillance procedure used to perform the monthly Bus 15 load sequencer test was permanently revised on October 17, 2008. Surveillance procedures for the remaining load sequencers were also revised. The inspectors reviewed the load sequencer surveillance test results from October 17, 2008, through April 2010, and found that the Bus 15 load sequencer failed the refueling outage surveillance test on October 17, 2009. The test failure was due to experiencing multiple error code 103 signals. The licensee initiated CAP 1202861 to document the test failure. The licensee also identified that the refueling outage load sequencer test procedures had not been revised to install the diagnostic laptop computer as part of the testing activities. After installing the diagnostic laptop computer, the licensee successfully re-performed the surveillance test an

additional 21 times. Due to the inability to recreate the test failure condition, the licensee concluded that the error code 103 signals were spurious.

On November 11, 2009, an operations individual initiated CAP 1207232 to document several items regarding the load sequencers. One of the items documented was a concern regarding whether connecting the diagnostic laptop computer as part of the monthly surveillance test could be preventing the receipt of error code 103 signals. Engineering notes attached to this CAP stated that the error code had been received while the diagnostic laptop computer was installed. In addition, engineering documented that the Bus 15 load sequencer had operated successfully for 6 months (without the laptop being installed) after the input/output cards were changed. However, engineering personnel acknowledged that no error codes had been received since the laptop's sampling rate was changed in October 2008. Engineering personnel also stated that the vendor was contacted to verify that the installation of the laptop would not interfere with the test results. The inspectors reviewed information attached to CAP 1207232 and found that the information provided from the vendor was contained in an email that was approximately two sentences in length. This email provided no technical basis to support that the diagnostic laptop was not influencing the surveillance test results. In addition, the licensee failed to recognize the need for a justification. Lastly, supervisory and management review of the corrective actions associated with CAP 1207232 failed to recognize the inadequate vendor justification prior to closing the corrective action document.

The inspectors brought this information to the attention of licensee management. In response to the inspectors concerns, the licensee contacted industry experts in PLCs, the load sequencer vendor and the vendor of the PLC contained within the load sequencer and requested that these groups review the possibility for potential interactions between the diagnostic laptop and the PLC. Based upon this review, the licensee was provided information that a potential interaction could occur. The licensee revised the load sequencer surveillance procedures to ensure that the diagnostic laptop was not installed prior to the surveillance test. The licensee also sent a diagnostic laptop to the load sequencer vendor for additional testing. The vendor subsequently determined that the installation of the diagnostic laptop had no impact on the surveillance test results.

Based upon the results of the subsequent vendor testing, no findings of significance were identified.

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

.1 Coupling Failure on 121 Motor Driven Cooling Water Pump

a. Inspection Scope

The inspectors reviewed the licensee's response to a self-revealing failure of the 121 motor driven cooling water pump. This review included observations of the licensee's pump disassembly and pump installation activities. The inspectors also reviewed the results of the licensee's apparent cause report. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

Introduction: A self-revealing finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion IV were identified due to the licensee's failure to have procurement documents in place to ensure that the 121 motor driven cooling water pump (MDCLP) shaft couplings were manufactured with the appropriate hardness. This resulted in the failure of two shaft couplings and an extended unavailability of the 121 MDCLP.

Description: At Prairie Island, the safety function of the cooling water system is normally accomplished using the 12 and 22 diesel driven cooling water pumps (DDCLP). However, the licensee maintained the 121 MDCLP as a safety-related component. This allowed the licensee the flexibility to re-configure the 121 MDCLP such that it could be used to accomplish the safety function of the cooling water system. On July 25, 2010, the licensee experienced a complete loss of discharge pressure for the 121 MDCLP due to the failure of two shaft couplings and the separation of their respective shaft segments. The licensee initiated CAP 1242770 to document the pump failure. The pump was subsequently repaired and reinstalled. Operations personnel returned the pump to service for safety-related applications on August 12, 2010.

The inspectors reviewed WO data and found that the 121 MDCLP was replaced (including the shaft bearings) in March 2009. The inspectors reviewed the results of the licensee's apparent cause evaluation and found that the pump shaft couplings had failed because Prairie Island had not provided a specific coupling hardness level to the vendor as part of the procurement process. The transmittal of the hardness information was required to ensure that the couplings would perform appropriately following installation. Since hardness information was not provided by the licensee, the couplings were manufactured to the vendor's hardness specifications. However, this hardness level increased the probability of coupling failure due to microbiologically induced corrosion, and trans-granular and inter-granular stress corrosion cracking.

The inspectors also reviewed the licensee's April 2010 response to Operating Experience Evaluation 1227159, "Licensee Event Report 2010-001, Potential Loss of Safety Function Due to a Service Water Pump Shaft Coupling Failure at Palisades." This operating experience documented a pump shaft coupling failure due to inadequate coupling hardness. The inspectors found that the operating experience had not been correctly evaluated. Specifically, the licensee incorrectly concluded that the couplings installed in the 121 MDCLP were manufactured by a different vendor. Following the failure of the 121 MDCLP, the licensee determined that the Prairie Island couplings were manufactured by the same vendor as the Palisades couplings.

Analysis: The inspectors determined that the failure to ensure that procurement documents for the 121 MDCLP shaft couplings contained appropriate information regarding coupling hardness was a performance deficiency that required an evaluation using the SDP. The inspectors determined that this issue was more than minor because it impacted the design control attribute of the Mitigating Systems Cornerstone. This finding also impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding did not qualify as an old design issue due to being self-revealed.

The inspectors performed a Phase 1 SDP screening and concluded that a Phase 2 SDP evaluation was required because the failure of the cooling water (CL) pump resulted in an actual loss of safety function of one or more risk significant, non-TS trains of equipment for greater than 24 hours. Using the pre-solved spreadsheets for the Risk-Informed Inspection Notebook for Prairie Island Nuclear Generating Plant (Revision 2.1a), the inspectors determined that the failure of a single cooling water pump to run for an exposure period of 3 – 30 days was a yellow finding. The regional SRA reviewed this result and determined that it was overly conservative and performed an SDP Phase 3 evaluation.

For the Phase 3 evaluation, the SRA used an exposure period of 18 days to represent the period of time that the pump was unavailable after the shaft coupling failure. The finding did not represent an increase in the likelihood of a Loss of Cooling Water Initiating Event because the other cooling water pumps were not susceptible to this failure mechanism and because of the overall redundancy in the CL system. The SPAR model for Prairie Island, Revision 8.15, was used in the evaluation. The delta CDF for the unavailability of the 121 MDCLP pump for 18 days was determined to be less than 1E-7/yr, which represents a finding of very low safety significance (Green). The dominant sequence was a loss of offsite power, seal LOCA and failure of the high pressure injection system. The inspectors determined that this finding was cross-cutting in the Problem Identification and Resolution, Corrective Action Program area because the licensee did not use operating experience to support plant safety. Specifically, the licensee did not implement changes to the 121 MDCLP after receiving and reviewing multiple pieces of operating experience regarding coupling failure due to hardness issues (P.2(b)).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion IV, Procurement Document Control, requires that measures be established to assure that applicable regulatory requirements, design bases, and other requirements which are necessary to assure adequate quality are suitably included or referenced in the documents for procurement and services, whether purchased by the applicant or by its contractors or subcontractors. Contrary to the above, prior to March 2009, the licensee failed to establish measures to assure that applicable regulatory requirements, design bases, and other requirements which are necessary to assure adequate quality are suitably included or referenced in the documents for procurement and services, whether purchased by the applicant or by its contractors or subcontractors. Specifically, procurement documents for the pump shaft couplings failed to include hardness information to assure that the couplings were procured with adequate quality. Because this violation was of very low safety significance and it was entered into your corrective action program as CAP 1242770, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000282/2010005-06; 05000306/2010005-06 Failure to Include 121 MDCLP Coupling Hardness Information in Procurement Document). Corrective actions for this issue included revising procurement documentation to include the hardness information, ensuring that the remaining CL pumps were not susceptible to the same coupling failure, and repairing the 121 MDCLP.

.2 (Closed) LER 05000282/2010-005: Surveillance Required by Technical Specification for the Emergency Diesel Generator Not Completed

This issue is discussed in Section 1R15.1.b(3) of this inspection report. A finding of very low safety significance and an NCV of TS 3.8.1 were identified. Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

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

4OA5 Other Activities

.1 Removal of Incorrect Radiation Monitor From Service

a. Inspection Scope

The inspectors attended the licensee's human performance event review board and reviewed operator logs, corrective action documents and procedures to determine the sequence of events that led to removing the incorrect radiation monitor from service on November 12, 2010.

b. Findings

Introduction: A self-revealing finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V was identified due to the licensee's failure to follow procedure while transferring the power supply for motor control center (MCC) 1T1 from Unit 1 to Unit 2. The failure to follow procedures resulted in removing safety-related radiation monitor 1R11/1R12 from service and an unplanned entry into TS LCO 3.4.16.B.

Description: On November 12, 2010, operations personnel performed activities to transfer power to MCC 1T1 from Unit 1 to Unit 2 using Procedure 1C20.6, "Unit 1 – 480 V System." Step 5.31.1.H of Procedure 1C20.6 contained a list of radiation monitors and directed operations personnel to remove the monitors from service using the applicable plant procedure. This list included Containment and Shield Building Air Radiation Monitor 2R11/2R12 (Unit 2 radiation monitors). Upon entering the auxiliary building, operations personnel removed Containment and Shield Building Air Radiation Monitor 1R11/1R12 (Unit 1 radiation monitors) from service. Control Room personnel immediately received alarms due to the incorrect radiation monitor being removed from service. Operations personnel also entered TS LCO 3.4.16.B due to this issue.

The licensee conducted a review of this event and determined that the following items contributed to removing the incorrect radiation monitor from service:

- The operator directing the work initially verbalized that Radiation Monitor 1R11/1R12 should be removed from service and marked up the corresponding procedure accordingly. When the operators found they had marked up the procedure incorrectly, the same procedure was re-marked to indicate the correct radiation monitor rather than marking up a new procedure;
- Imprecise communications were utilized by operations personnel while preparing to remove the radiation monitor from service. These communications were not corrected to ensure the correct piece of equipment was removed from service;

- Operations personnel failed to perform a pre-job briefing prior to removing the radiation monitor from service as required by procedure; and
- The operator within the auxiliary building failed to use human performance tools to ensure that he was removing the correct radiation monitor from service.

Analysis: The inspectors determined that the failure to follow procedures while transferring power for MCC 1T1 from Unit 1 to Unit 2 was a performance deficiency that required an evaluation using the SDP. This finding was associated with the Mitigating Systems Cornerstone because the radiation monitor was used to detect a RCS leak such that additional actions could be taken to prevent core damage. The inspectors determined that this finding was more than minor because, if left uncorrected, the performance of plant activities on the incorrect unit would become a more significant safety concern. The inspectors concluded that this finding was of very low safety significance because it was not caused by a design deficiency, did not result in a loss of safety function, did not result in a loss of safety function of one train for greater than the TS allowed outage time, and did not screen as potentially significant due to a seismic, severe weather or flooding event. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because personnel failed to use human error prevention techniques to ensure that work was performed safely (H.4(a)).

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

Procedure 1C20.6, "Unit 1 – 480 V System," was a system operating procedure which provided instructions for manipulating safety-related equipment (an activity affecting quality).

Step 5.31.1.H of Procedure 1C20.6 directed operations personnel to removed radiation monitor 2RE11/2RE12 from service per Procedure C11, "Radiation Monitoring System."

Step 5.4.8.E of Procedure C11 directed operations personnel to place both skid RAM606 key switches in the off position locally at the 2R11/2R12 skid.

Contrary to the above, on November 12, 2010, operations personnel failed to place both skid RAM606 key switches in the off position locally at the 2R11/2R12 skid. Instead, operations personnel manipulated the skid RAM606 key switches for 1R11/1R12 which resulted in removing the incorrect monitor from service. Because this violation was of very low safety significance and it was entered into your corrective action program as CAP 1258320, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000282/2010005-07, Failure to Follow Procedure Results in Removing Incorrect Radiation Monitor From Service). Corrective actions for this issue included returning radiation monitor 1R11/1R12 to service and re-enforcing the use of human performance tools to operations personnel.

.2 (Closed) URI 05000282/2010004-01; 05000306/2010004-01: Potential Inadequate Protection of 122 Control Room Chiller

a. Inspection Scope

The inspectors reviewed the licensee's completed corrective action documentation for NRC URI 05000282/2010004-01; 05000306/2010004-01. This item was initially documented in Section 1R04 of NRC Inspection Report 2010004.

a. Findings

Introduction: An inspector identified finding of very low safety significance and an associated NCV of 10 CFR Part 50.65(a)(4) were identified due to the failure to properly assess the risk associated with performing planned maintenance activities on the 111 switchgear unit cooler and the 121 control room chiller. Although the 122 control room chiller was classified as protected equipment, the licensee failed to identify that the draining of safeguards chilled water from the 111 switchgear unit cooler would result in a loss of suction pressure to the 122 control room chiller pump.

Description: On August 31, 2010, maintenance personnel performed planned maintenance to replace two valves (CV-31755 and 2ZH-6-4) on the 111 switchgear unit cooler. Work orders 373588 and 108888 defined the activities associated with each valve. Prior to the valve replacements, maintenance personnel were required to drain the safeguards chilled water within the 111 switchgear unit cooler's isolation boundary.

At the same time the 111 switchgear unit cooler was being drained, the inspectors performed a partial equipment alignment of the 122 control room chiller due to the chiller being considered protected equipment. During the walkdown, the inspectors noted that the suction pressure for the 122 control room chiller pump was less than the pressure band specified in the operating procedure and was steadily decreasing. The inspectors immediately contacted the control room to inform them of the decreasing pump suction pressure. The control room dispatched local operators to the scene to re-pressurize the system. In addition, control room operators recognized that the draining activity for the 111 switchgear unit cooler may have caused the loss of suction pressure to the 122 control room chiller pump. Maintenance workers in the 111 switchgear room were contacted and told to stop all work activities. Operator actions to re-pressurize the system prevented the chiller pump from tripping due to low suction pressure. Had the pump tripped, operations personnel would have been required to enter TS 3.0.3 for both units due to two inoperable control room chillers.

The inspectors discussed the maintenance planning and work control activities associated with the WOs with production planning personnel. The inspectors were informed that the safeguards chilled water system was operating in a cross connected configuration. However, the impact of having the system cross connected while draining activities were taking place was not recognized. The inspectors were also told that maintenance personnel had voiced concerns regarding the leak-tightness of the safeguards chilled water isolation valves, and the need for additional compensatory measures, several weeks before the maintenance was performed. No additional measures were put in place. Lastly, the inspectors reviewed the licensee's maintenance risk assessment for August 31, 2010. The inspectors found that both the 111 switchgear unit cooler and the 121 control room chiller maintenance were considered normal risk

per Procedure FP-WM-IRM-01, “Integrated Risk Management.” The inspectors reviewed the licensee’s maintenance work planning and integrated risk management procedures and found that the procedure required this work to be screened for high risk (it was not) and potentially scheduled for another date since the interaction between the two maintenance activities would have likely caused an entry into a TS limiting condition for operation of less than 72 hours (if not for the inspectors’ discovery) and because the activity, if performed incorrectly, would significantly increase the probability of a plant transient.

Analysis: The failure to properly assess and manage risk during maintenance activities, specifically those that could affect safeguards chilled water and the operability of protected equipment, was a performance deficiency that required an SDP evaluation. The inspectors determined the finding was more than minor, based in part on Example 7g of IMC 0612, Appendix E, which describes a condition where a safety function is significantly degraded without sufficient compensation. This finding was also more than minor because, if left uncorrected, the issue would have resulted in the need to shut down both reactors due to a loss of control room cooling function (a more significant safety concern). This issue was associated with the Barrier Integrity Cornerstone. This finding was determined to be of very low safety significance because it was not specific to the radiological barrier provided by the control room ventilation system; was not a degradation of the barrier function of the control room against smoke or a toxic atmosphere; did not represent an actual open pathway in the reactor containment; and it did not involve an actual reduction in the function of the hydrogen igniters. The inspectors concluded that this finding was cross-cutting in the area of Human Performance, Work Control area because the licensee did not plan and coordinate work activities consistent with nuclear safety. (H.3(a)).

Enforcement: Title 10 CFR 50.65 a(4) requires, in part, that before performing maintenance, licensees must properly assess and manage risk. Procedure FP-WM-PLA-01, “Work Order Planning Process,” Step 3.3.3, states that maintenance planners are responsible for performing risk assessments per FP-WM-IRM-01, “Integrated Risk Management.”

Step 5.1.1 of FP-WM-IRM-01 states that all plant work shall be screened using this procedure to determine the potential risk significance.

Step 5.1.2 of FP-WM-IRM-01 states that maintenance, radiation protection, and operations planners perform the initial task risk screening of work order tasks by following QF-2010, “Work Order Risk Screening Worksheet.”

QF-2010, Section 1.A.1 asks whether the activity, if performed incorrectly, would increase the possibility of a plant transient. In addition, Section 1.A.11, asks if the work causes entry into a 72 hour LCO. If yes, Procedure FP-WM-IRM-01 requires that the work be screened for high risk by completing Section 2 of QF-2010.

Contrary to the above, on August 31, 2010, licensee personnel failed to properly assess and manage the risk associated with planned maintenance on the 111 switchgear unit cooler and the 121 control room chiller. Specifically, maintenance planning personnel failed to recognize that this maintenance activity significantly increased the possibility of a plant transient due to a dual unit TS 3.0.3 entry and that the maintenance would have caused entry into a TS LCO of 72 hours or less. As a result, the work was not screened

for high risk and additional risk management actions were not implemented. Because this finding was of very low safety significance, and it was entered into CAP 1247908, this violation is being treated as an NCV consistent with Section VI.A of the Enforcement Policy (NCV 05000282/2010005-08 / 05000306/2010005-08; Failure to Properly Assess and Manage Risk During Planned Maintenance Activity). Corrective actions for this issue included the development of an improved operator turnover process to ensure personnel were aware of system draining activities and adding warnings to clearance orders for the safeguards chilled water system to ensure that individuals were aware of potential system interactions.

.3 Measurement Uncertainty Recapture Power Uprate Inspection Activities (71004)

a. Inspection Scope

On December 28, 2009, Northern States Power Company - Minnesota requested changes to their Operating Licenses to increase the maximum thermal power for the Prairie Island Nuclear Generating Plant. These changes, which were approved by the NRC on August 18, 2010, allowed the licensee to increase the thermal power output of each Prairie Island reactor from 1650 megawatts thermal (MWt) to 1677 MWt. NRC documentation refers to this type of power level increase as an MUR uprate. This type of power uprate was not required to be inspected per NRC IP 71004, "Power Uprate," because the reactor was previously analyzed to operate at this power level during initial licensing. However, the inspectors performed portions of the inspection procedure to ensure that risk-significant portions of the power uprate were performed safely.

The inspectors developed an inspection plan using the guidance provided in Attachment 2 to IP 71004. Inspection activities were completed in the following areas:

Inspection Plan Item	Item Description	IPs Used	Inspection Report Containing Inspection Sample
Plant Modifications	Verification of the following: -Re-scaling plant control and protection instrumentation -Revisions to the Emergency Response Computer System (ERCS) and secondary calorimetric programs	71004	05000282/2010005; 05000306/2010005

Integrated Plant Operations at Uprated Power Level	Verification of the following: -Control room alarm response procedures revised to account for new leading edge flow meter administrative limits -ERCS and simulator program changes made to reflect new licensed power levels -Required changes to abnormal and emergency response procedures completed -Power ascension activities for both units completed safely -Training provided to all operations personnel regarding plant changes due to MUR power uprate implementation	71111.11 71004	05000282/2010005; 05000306/2010005

Flow Accelerated Corrosion and Erosion/Corrosion Program Review	Verification of the following: -CHECWORKS models were revised to include changes in moisture carryover, pressure and flowrate as a result of MUR implementation	71004	05000282/2010005; 05000306/2010005
Identification and Resolution of Problems	Verification of the following: -Licensee developed an MUR power ascension monitoring program to aid in identifying new problems -Operations personnel maintained reactor power less than 100 percent to account for feedwater regulating valve oscillations	71152 71004	05000282/2010005; 05000306/2010005

	-Licensee was taking action to address a main steam line piping overstress condition documented previously		

(1) Plant Modifications

The inspectors reviewed documentation; interviewed operations, engineering and maintenance personnel; and observed work activities for the MUR power uprate activities listed below. During the observations of work activities the inspectors validated control room indications to ensure that the plant was responding as expected. Lastly, the inspectors reviewed issues placed into the licensee's CAP to ensure that the issues were promptly corrected.

Unit 1:

- WO 404305-04 – Perform Unit 1 Pre-Uprate Calorimetric
- WO 404305-05 – Perform Pre-Uprate Adjustment of Unit 1 Nuclear Instrumentation Power Range
- WO 404305-06 – Perform Update of Unit 1 ERCS Computer Programs
- WO 404305-07 – Perform MUR Pre-Uprate Calorimetric
- WO 404305-08 – Perform Unit 1 MUR Pre-Uprate Loop Delta Temperature Calibrations
- WO 404305-09 – Perform Pre-Uprate Turbine First Stage Pressure Calibration

Unit 2:

- WO 404306-04 – Perform Unit 2 Pre-Uprate Calorimetric
- WO 404306-05 – Perform Pre-Uprate Adjustment of Unit 2 Nuclear Instrumentation Power Range
- WO 404306-06 – Perform Update of Unit 2 ERCS Computer Programs
- WO 404306-07 – Perform MUR Pre-Uprate Calorimetric
- WO 404306-08 – Perform Unit 2 MUR Pre-Uprate Loop Delta Temperature Calibrations
- WO 404306-09 – Perform Pre-Uprate Turbine First Stage Pressure Calibration

No findings of significance were identified.

(2) Integrated Plant Operations at Uprated Power Level

Prior to the licensee's MUR implementation, the inspectors observed training provided to engineering and operations personnel regarding MUR implementation and integrated plant operations at the new power level. The inspectors reviewed training presentations from earlier training sessions to ensure that all aspects of MUR implementation and potential changes to integrated plant operations were discussed. Lastly, the inspectors reviewed the licensee's training attendance records to verify that all licensed operators and NLOs had received training prior to the MUR implementation.

The inspectors attended the pre-job briefings and observed portions of the MUR power ascension activities as described in WOs 404305-12 (Unit 1) and WO 404306-12 (Unit 2). During the pre-job briefing observations the inspectors verified the following:

- All associated departments were represented at the briefing;
- Details of the power ascension plan (including hold points) and the reactivity plan were discussed;
- In-plant walkdown teams understood their roles, responsibilities and items identified during the pre-MUR implementation walkdown of plant equipment;
- The use of human performance tools was re-enforced;
- Critical steps were marked within each WO and discussed;
- Stop work criteria were discussed; and
- Communication and decision making protocols were understood.

Following the MUR implementation, the inspectors performed several control room observations to verify that the reactors were operating as expected. During the inspection discussed in Section 1R11 of this report, the inspectors reviewed simulator control board indications to ensure that these indications had been revised to reflect reactor operation at MUR power levels.

No findings of significance were identified.

(3) Flow Accelerated Corrosion and Erosion/Corrosion Program Review

The inspectors reviewed documentation and verified that the CHECWORKS models were revised to account for MUR conditions on September 9, 2010.

(4) Identification and Resolution of Problems

The inspectors reviewed the licensee's resolution of the following issues as part of the NRC's MUR inspection activities:

Development and Implementation of MUR Monitoring Plan

Prior to the MUR implementation, the inspectors met with engineering and projects personnel to discuss the MUR monitoring plan. The purpose of this plan was to determine the status of plant equipment prior to, during, and after the MUR was implemented. Based upon the results of this meeting, the inspectors were concerned that the licensee had not developed a MUR monitoring plan of sufficient breadth, depth, and duration to ensure that the plant continued to operate as expected during and following MUR implementation activities. The inspectors discussed these concerns with licensee personnel. The licensee revised the MUR monitoring plan to ensure that the monitoring of plant equipment before, during and after the MUR implementation was performed by an experienced and cross-disciplined team of licensee personnel. The licensee also established periodic plant walkdowns, which occurred for several weeks following the MUR implementation, to ensure that plant conditions and equipment were not changing with time. The inspectors performed an independent review of plant conditions before, during, and after the MUR was implemented. The results of the independent review were compared to the licensee's monitoring plan results to verify that the licensee maintained an appropriate low threshold for identifying potential problems. Lastly, the inspectors reviewed the resolution of several CAP documents

initiated during the MUR implementation to ensure that the corrective actions were appropriate.

No findings of significance were identified.

Implementation of Feedwater Regulating Valve Corrective Actions

For some time, the licensee has experienced oscillations of their feedwater regulating valves. Although the licensee had taken several actions to address the oscillations, these actions have not fully corrected this condition.

NRC Regulatory Issue Summary 2007-21,"Adherence of Licensed Power Limits," informed licensee's that short-term fluctuations in reactor power caused by feedwater flow oscillations were acceptable as long as the oscillations were inherent to the design of the feedwater system. Conversely, licensee's were not allowed to operate with short-term fluctuations of reactor power (over 100 percent) if the fluctuations were caused by an equipment deficiency. The inspectors reviewed several corrective action evaluations and found that the licensee had concluded that the oscillations were not inherent to the feedwater system design.

Prior to the MUR implementation, the inspectors performed several tours of the control room and determined that operations personnel were operating both of the reactors at reduced power levels to ensure that the feedwater control valve oscillations would not result in operating the reactor above the licensed power level. Following the MUR implementation, the inspectors performed additional control room tours and verified that operations personnel continued to account for feedwater oscillations while operating the plant.

No findings of significance were identified.

Resolution of Main Steam Piping Overstress Condition (CAP 1223633)

On March 22, 2010, the licensee identified that the current stress analyses of record for the main steam system did not include the seismic loads from building torsional acceleration. The licensee performed an interim analysis in accordance with Prairie Island Engineering Manual 3.2.1.1, "Specification for the Stress Analysis of Piping Systems," and determined that the new stress levels did not exceed the operability limits specified in Section 6.5.2 of Engineering Manual 3.2.1.1. Specifically, the stress levels did not exceed two times the material yield stress. The licensee also evaluated the impact of the additional stress on the main steam line anchors, restraints, and penetrations. The licensee concluded that sufficient margin was available to ensure that the anchors, restraints and penetrations would continue to perform their function during a seismic event. The licensee planned to incorporate these calculations into their main steam piping analyses of record during 2011.

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 13, 2011, the inspectors presented the inspection results to Mr. M. Schimmel, 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 licensed operator requalification training program annual operating test results via telephone with Mr. T. Ouret, Supervisor Operations Training, on November 3, 2010.

The inspector confirmed that none of the potential report input discussed was considered proprietary. No proprietary material was received during the inspection.

.3 Regulatory Performance Meeting

On December 14, 2010, the NRC met with the licensee to discuss their performance in accordance with Section 06.05.a.1 of IMC 0305. During this meeting, the NRC and licensee discussed the issues related to interactions of high energy piping with the component cooling water system. This white finding resulted in Unit 2 being placed in the Regulatory Response Column of the Action Matrix. This discussion included the causes, corrective actions, extent of condition, extent of cause, and other planned licensee actions.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
M. Schimmel, Site Vice President
K. Davison, Plant Manager
T. Roddey, Site Engineering Director
J. Anderson, Regulatory Affairs Manager
C. Bough, Chemistry and Environmental Manager
B. Boyer, Radiation Protection Manager
K. DeFusco, Emergency Preparedness Manager
D. Goble, Safety and Human Performance Manager
J. Hamilton, Security Manager
J. Lash, Nuclear Oversight Manager
R. Madjerich, Production Planning Manager
M. Milly, Maintenance Manager
J. Muth, Operations Manager
S. Northard, Performance Improvement Manager
A. Notbohm, Performance Assessment Supervisor
T. Ouret, Supervisor Operations Training
K. Peterson, Business Support Manager
A. Pullam, Training Manager
R. Womack, Outage Manager

Nuclear Regulatory Commission
J. Giessner, Chief, Reactor Projects Branch 4
T. Wengert, Project Manager, NRR

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000282/2010005-01	NCV	Failure to Perform Adequate Post Modification Testing Following Battery Charger Replacement (Section 1R15)
05000282/2010005-02	NCV	Failure to Complete Operability Determinations in accordance with Procedural Requirements (Section 1R15)
05000282/2010005-03	NCV	Failure to Ensure Compliance with TS SR 3.8.1.10c (Section 1R15)
05000306/2010005-04	NCV	Failure to Appropriately Complete an Operability Determination on D5 EDG (Section 1R15)
05000282/2010005-05; 05000306/2010005-05	URI	Potential for Common Mode Failure of Safety-Related Battery Chargers (Section 1R15)
05000282/2010005-06; 05000306/2010005-06	NCV	Failure to Include 121 MDCLP Coupling Hardness Information in Procurement Document (Section 4OA3.1)
05000282/2010005-07	NCV	Failure to Follow Procedure Results in Removing Incorrect Radiation Monitor From Service (Section 4OA5.1)
05000282/2010005-08; 05000306/2010005-08	NCV	Failure to Properly Assess and Manage Risk During Planned Maintenance Activity (Section 4OA5.2)

Closed

05000282/2010005-01	NCV	Failure to Perform Adequate Post Modification Testing Following Battery Charger Replacement (Section 1R15)
05000282/2010005-02	NCV	Failure to Complete Operability Determinations in accordance with Procedural Requirements (Section 1R15)
05000282/2010005-03	NCV	Failure to Ensure Compliance with TS SR 3.8.1.10c (Section 1R15)
05000306/2010005-04	NCV	Failure to Appropriately Complete an Operability Determination on D5 EDG (Section 1R15)
05000282/2010005-06; 05000306/2010005-06	NCV	Failure to Include 121 MDCLP Coupling Hardness Information in Procurement Document (Section 4OA3.1)
05000282/2010-005	LER	Surveillance Required by Technical Specification for the Emergency Diesel Generator Not Completed (Section 4OA3.2)
05000282/2010005-07	NCV	Failure to Follow Procedure Results in Removing Incorrect Radiation Monitor From Service (Section 4OA5.1)
05000282/2010005-08; 05000306/2010005-08	NCV	Failure to Properly Assess and Manage Risk During Planned Maintenance Activity (Section 4OA5.2)
05000282/2010004-01; 05000306/2010004-01	URI	Potential Inadequate Protection of 122 Control Room Chiller (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

- Heath and Status Report; Screenhouse Ventilation; November 12, 2010
- Procedure TP 1637; Winter Plant Operation; Revision 43
- Procedure C37.5; Screenhouse Normal Ventilation; Revision 8
- CAP 746376; 21 Class 1 Roof Exhaust Fan Discharge Damper; August 8, 2004
- CAP 1167617; Inappropriate Guidance Given to Verify Winter Preparedness; January 31, 2009
- CAP 1165338; Loss of Auto Start Capability for All Fire Protection Pumps; January 13, 2009
- Evaluation 1165338; Loss of Auto Start Capability for All Fire Protection Pumps Occurred on 1/13/09; February 27, 2009
- CAP 1177505; Temporary Modification Requested to Place #11 Screenhouse Exhaust Fan in Service; April 4, 2009
- WO 383328; Temporary Modification Required to Hold open CD-34135; June 9, 2009
- WO 361221; U0, CD-34135, Refurbish 11 Screenhouse Exhaust Damper, April 16, 2010
- CAP 1093404; Fan Flow Rates not Revalidated following System Configuration Change; May 21, 2007
- Evaluation 1093404; Flow Rates for the Safeguards Screenhouse Exhaust Fans; May 25, 2007
- CAP 1095615; Screenhouse Ventilation (ZR) Backdraft Damper Classification; June 7, 2007
- CAP 1096073; Short-Circuit Airflow Potential in Screenhouse Ventilation (ZR) System; June 6, 2007
- Evaluation 1096073; Short-Circuit Airflow Potential in Screenhouse Ventilation (ZR) System; June 15, 2007
- Drawing NF-39603-1; Administration Building, Screenhouse, and Control Room Flow Diagram, Revision 78
- Maintenance Rule System Specific Basis Document; Revision 15
- Procedure H24; Maintenance Rule Program; Revision 17

1R04 Equipment Alignment

- C28-2; Auxiliary Feedwater System Unit 1; Revision 47
- Heath and Status Report; Screenhouse Ventilation; November 12, 2010
- Procedure TP 1637; Winter Plant Operation; Revision 43
- Procedure C37.5; Screenhouse Normal Ventilation; Revision 8
- Checklist C37.5-1; Screenhouse Normal Ventilation; Revision 5
- Checklist C37.8-1; Screenhouse Safeguards Ventilation System; Revision 5
- CAP 746376; 21 Class 1 Roof Exhaust Fan Discharge Damper; August 8, 2004
- CAP 1167617; Inappropriate Guidance Given to Verify Winter Preparedness; January 31, 2009
- CAP 1165338; Loss of Auto Start Capability for All Fire Protection Pumps; January 13, 2009
- Evaluation 1165338; Loss of Auto Start Capability for All Fire Protection Pumps Occurred on 1/13/09; February 27, 2009

- CAP 1177505; Temporary Modification Requested to Place #11 Screenhouse Exhaust Fan in Service; April 4, 2009
- WO 383328; Temporary Modification Required to Hold open CD-34135; June 9, 2009
- WO 361221; U0, CD-34135, Refurbish 11 Screenhouse Exhaust Damper, April 16, 2010
- CAP 1093404; Fan Flow Rates not Revalidated following System Configuration Change; May 21, 2007
- Evaluation 1093404; Flow Rates for the Safeguards Screenhouse Exhaust Fans; May 25, 2007
- CAP 1095615; Screenhouse Ventilation (ZR) Backdraft Damper Classification; June 7, 2007
- CAP 1096073; Short-Circuit Airflow Potential in Screenhouse Ventilation (ZR) System; June 6, 2007
- Evaluation 1096073; Short-Circuit Airflow Potential in Screenhouse Ventilation (ZR) System; June 15, 2007
- Drawing NF-39603-1; Administration Building, Screenhouse, and Control Room Flow Diagram, Rev 78
- Maintenance Rule System Specific Basis Document; Revision 15
- Procedure H24; Maintenance Rule Program; Revision 17

1R05 Fire Protection

- Fire Hazards Analysis
- Safe Shutdown Analysis
- Procedure F5, Appendix A; Fire Zone Plans and Maps; Various Revisions

1R11 Licensed Operator Requalification

- Simulator Exercise Guide LOR Cycle 10G Simulator Evaluation; Revision 1
- Results of Annual Operating Test; November 3, 2010

1R12 Maintenance Effectiveness

- Maintenance Rule A(1) Action Plan; 22 DDCLP Unavailability Criteria Exceedence, Revision C; April 5, 2010
- Maintenance Rule System Specific Basis Document; Revision 15
- CAP 1218063; Generate an A(1) Action Plan IAW A24 5.7.4; February 12, 2010
- WO 399250; U0, SA-49-2, Can't Press Up 22 DDCLP Air Start Receiver; January 23, 2010
- CAP 1226223; Evaluate if Adequate Preventive Maintenance is being Performed on Air Compressors; April 7, 2010
- PMCR 1222314; Preventive Maintenance Change Request for Air Compressors, April 23, 2010
- CAP 1215266; 122 Diesel Cooling Water Pump Oil Storage Tank Pump Failure- Unplanned LCO; January 26, 2010
- Evaluation 1215266; 122 Diesel Cooling Water Pump Oil Storage Tank Pump Failure- Unplanned LCO; February 25, 2010
- Procedure FP-E-CAP-01; Electrolytic Capacitor Aging Management, Revision 2
- CAP 1221106; Replace the Motor Capacitors for the Unit 1 Fuel Oil Transfer Pumps; March 3, 2010
- PMCR 1221106; Preventive Maintenance Change Request for Motor Capacitors in Fuel Oil Transfer Pumps; August 23, 2010

1R13 Maintenance Risk Assessment and Emergent Work

- H24.1 Appendix A; Phase 1 Risk Assessment Preparation; Revision 4

1R15 Operability Evaluations

- QF-1129; Time Critical Operator Actions Evaluation for Dedicated Operator Performing Restart of Battery Chargers; Multiple Scenarios
- Operator Logs; October 22, 2010
- Operator Logs; November 8, 2010
- Prairie Island Nuclear Generating Plant Design Bases Document; Emergency Diesel Generator System; Revision 3
- Prairie Island Nuclear Generating Plant Design Bases Document; DC Auxiliaries System; Revision 5
- Alarm Response Procedure C47524-1203; D5 Emergency Diesel Generator Local Alarm; Revision 37
- 1E-0; Reactor Trip and Safety Injection; Revision 26A
- 1C20.9 AOP2; Loss of Unit 1 Train B DC; Revision 5
- 1C20.9 AOP3; Failure of 11 Battery Charger; Revision 9
- 1C20.9 AOP4; Failure of 12 Battery Charger; Revisions 10 and 10A
- 2C20.7; D5/D6 Diesel Generators; Revision 35
- SP 2093; D5 Diesel Generator Monthly Slow Start Test; Revision 89
- SP 2305; D6 Diesel Generator Monthly Slow Start Test; Revision 33
- ICPM 2-507; D5 Fuel Oil Day Tank Level Switch Functional Test; Revision 2
- L-PI-10-098; Exigent License Amendment Request to Modify Technical Specifications Surveillance Requirement 3.8.1.10 for Prairie Island Nuclear Generating Plant Unit 1; October 14, 2010
- L-PI-10-100; Response to NRC Request for Additional Information received October 15, 2010, related to Exigent License Amendment Request to Modify Technical Specifications Surveillance Requirement 3.8.1.10 for Prairie Island Nuclear Generating Plant Unit 1; October 16, 2010
- L-PI-10-101; Second Response to NRC Request for Additional Information received October 15, 2010 related to Exigent License Amendment Request to Modify Technical Specifications Surveillance Requirement 3.8.1.10 for Prairie Island Nuclear Generating Plant Unit 1; October 17, 2010
- L-PI-10-102; Response to NRC Request for Additional Information received October 17, 2010, related to Exigent License Amendment Request to Modify Technical Specifications Surveillance Requirement 3.8.1.10 for Prairie Island Nuclear Generating Plant Unit 1; October 18, 2010
- L-PI-10-104; Supplement to Exigent License Amendment Request to Modify Technical Specifications Surveillance Requirement 3.8.1.10 for Prairie Island Nuclear Generating Plant Unit 1 (TAC No. ME4871); October 20, 2010
- L-PI-10-105; Licensee Event Report 50-282/2010-005-00, Surveillance Required by Technical Specifications for the Emergency Diesel Generator Not Completed; November 8, 2010
- Apparent Cause Evaluation 1238842; Testing Configuration Could Potentially Prevent D2 Diesel Generator and 12 Battery Charger from Fulfilling Design Functions; August 12, 2010
- CAP 1252265; Questions Related to OPR and Reportability for CAP 1238842; September 30, 2010
- CAP 1253478; Concerns with the OPR from 1238842 on 12 Battery Charger; October 9, 2010
- CAP 1254278; AR 1241533 Closed to AR 1238842 Inappropriately; October 15, 2010
- CAP 1254336; D6 1A Air Compressor Failed to Shut Off at Setpoint; October 16, 2010

- CAP 1254359; Compensatory Measures Not Evaluated Properly; October 16, 2010
- CAP 1258250; Timing of OPR Approval and LCO Exit; November 11, 2010
- Work Request (WR) 38115; Unit 2 Calibrate Transmitter and Level Switch D5 Fuel Oil Day Tank Hi-Hi Alarm; September 9, 2010
- WR 62016; D5 Fuel Oil Day Tank Auto Level Control Problems; November 8, 2010
- WR 62147; Maintenance Suspects D5 Day Tank High Level Switch Malfunctioning; November 13, 2010
- WR 62149; Functional Test of the D6 Day Tank Level Control; November 13, 2010
- WR 62141; D5 Fuel Oil Day Tank Auto Level Control Problems; November 13, 2010
- WO 368925; Unit 2 Calibrate Transmitter and Level Switch D5 Fuel Oil Day Tank Hi-Hi Alarm; October 5, 2010
- WO 389958; ICPM 2-507D5 Fuel Oil Day Tank Level Switches Calibration; October 14, 2010
- WO 417087; D5 Fuel Oil Day Tank Auto Level Control Problems; November 11, 2010
- WO 417173; D5 Fuel Oil Day Tank Auto Level Control Problems; November 13, 2010
- Drawing NE-40406-107; Revision MM
- Drawing NF-118845; Revision D
- Drawing NE-116756-25; Revision A
- Drawing NE-116756-26; Revision A
- Operating Information 10-107; October 18, 2010
- Training Records for Job Performance Measures DC-4 and DC-5
- V.SPA.10-012; Risk Evaluation for Emergency Diesel Generator D2 Missed Surveillance Test; Revision 1
- NRC Information Notice 97-78; Crediting of Operator Actions in Place of Automatic Actions and Modifications of Operator Actions, Including Response Times; October 23, 1997
- 10 CFR 50.59 Screening No. 3531; 12 Battery Charger 1E0 Attachment L and AOP Changes as Compensatory Measures for OPR 1238842; July 1, 2010
- NRC Inspection Manual Part 9900 Technical Guidance; Resolution of Degraded and Nonconforming Conditions; October 8, 1997
- NRC TIA 2008-004; Evaluation of Application of Technical Specification 4.0.3 at Pilgrim; January 23, 2009
- Nonconformance Report 19971622; Intermittent Operation During SP 1083; December 5, 1997

<u>1R18 Modifications</u>

- EC 16614; Portable Air Compressor in the Intake Screen House; Revision 1
- 50.59 Screening 3556; Portable Air Compressor in the Intake Screenhouse and Temporary Power Supply in Excess of 90 Days; Revision 0

<u>1R19 Post Maintenance Testing</u>

- MSIP 5007; ITT Grinnell Hand and Air Operated Valves; Revision 15
- WO 405904; Replace Bonnet on 23 Charging Pump Suction Valve 2VC-6-7; November 2, 2010
- ASME Section XI Repair and Replacement Plan 2-26-006; no date
- Equivalent Engineering Change 1554; October 17, 2004
- SP 1095; Bus 16 Load Sequencer Test; Revision 30

1R22 Surveillance Test

- SP 1093; D1 Diesel Generator Monthly Slow Start Test; Revision 83
- WO 405650-01; SP 1093 D1 Diesel Generator Monthly Slow Start; October 11, 2010
- SP 1094; Bus 15 Load Sequencer Test; Revision 28
- WO 405654-01; SP 1094 Bus 15 load Sequencer Monthly Test; October 12, 2010
- 1C20.7; D1/D2 Diesel Generators; Revision 28
- SP 1245A; 11/13 Fan Coil Unit ZX Valves Stroke Quarterly Test; Revision 9
- WO 410275-01; SP 1245A 11/13 Fan Coil Unit ZX Valves Stroke Quarterly Test; October 7, 2010
- SP 1245B; 12/14 Fan Coil Unit ZX Valves Stroke Quarterly Test; Revision 10
- WO 410279-01; 12/14 FCU ZX Valves Stroke Quarterly; October 14, 2010
- C37.13; Containment and Auxiliary Building Cooling System; Revision 37
- SP 2001 AA; Reactor Coolant System Leakage Test; Revision 49

4OA1 Performance Indicator Verification

- MSPI Derivation Report; Residual Heat Removal System; October 2009 through September 2010
- MSPI Derivation Report; Cooling Water System; October 2009 through September 2010

4OA2 Identification and Resolution of Problems

- Unit 1 Turnover Log; November 19, 2010
- Unit 1 Turbine Building Turnover Log; November 19, 2010
- Unit 2 Turnover Log; November 19, 2010
- Unit 2 Turbine Building Turnover Log; November 19, 2010
- Auxiliary Building Turnover Log; November 19, 2010
- Operator Burden Report Summary; September – November 2010
- FP-OP-OB-01; Operator Burden Program; Revision 1
- 5AWI 3.10.8; Equipment Problem Resolution Process; Revision 13
- WM-0501; Operator Burden Report; November 17, 2010
- CAP 1253343; Unresolved Issues with new Load Sequencer Laptop; October 8, 2010
- ACE 1234321-01; Organizational Issues Related to Load Sequencer Problems; September 20, 2010
- Operational Decision Making Issue Evaluation 1223694-03; Laptop Computer may Mask 103 Error Code; May 24, 2010
- CAP 1232901; Bus 15 Load Sequencer Failed during SP 1094; May 14, 2010
- CAP 1234321; Evaluate Organizational Gaps – Bus Sequencer Surveillances; May 24, 2010
- CAP 1223267; Bus 16 Load Sequencer Card Replacement Rescheduled; March 18, 2010
- CAP 1207232; Load Sequencer Alarm Sensing Capabilities with Laptop; November 17, 2009
- CAP 1229849; Load Sequencer Procedures Need to be Revised; April 28, 2010
- CAP 1140224; NRC Question Regarding Testing for Load Sequencers; June 6, 2008
- CAP 1144132; Inadequate Corrective Action to Prevent Recurrence resulted in Incomplete Actions; July 14, 2008
- CAP 1152949; Unplanned LCO Entry due to Bus 15 Sequencer Inoperable; September 30, 2008
- CAP 1155550; Load Sequencer Surveillances Not Revised Prior to Performing; October 15, 2008
- CAP 1156968; Level A CAP Action Complete Without Work Completed; October 27, 2008

- CAP 1158587; Effectiveness Reviews for Load Sequencer Root Cause Evaluation 1121937 Less Than Adequate; November 7, 2008
- CAP 1188446; Bus 26 Load Sequencer P2 Power Supply Showing Signs of Degradation; July 7, 2009
- CAP 1202861; Bus 15 Sequencer Failed SP 1119; October 17, 2009
- CAP 1121937; Failure to Meet SR 3.3.4.2 Makes Bus 15 Load Sequencer Inoperable; December 21, 2007
- NOS Observation Report 2010-02-026; NOS Review of Load Sequencer Error Code Issue; May 15, 2010
- Email from Richard Kaylor, Spectrum Technologies to Jonathan Ryan, Xcel Energy; October 27, 2009
- ATC Nuclear Job Number JN10N3760; Results of Timing Tests for Safeguards Load Sequencer Error 103; June 23, 2010

4OA3 Follow-up of Events and Notices of Enforcement Discretion

- ACE 1242770; Shaft Coupling Failure of 121 Motor Driven Cooling Water Pump; September 23, 2010

4OA5 Other Activities

- WO 404305-01; Predicted MUR Plant Parameters for Unit 1
- Unit 1 MUR Power Ascension Monitoring Plan
- Unit 2 MUR Power Ascension Monitoring Plan
- NRC Safety Evaluation for Amendments 197 and 186 to Licenses DPR-42 and DPR-60; August 18, 2010
- CAP 1254305; 11 Feedwater Pump Discharge Pipe Movement Observation During Unit 1 Power Ascension; October 15, 2010
- CAP 1253440; Unit 2 First Stage Pressure pt485/pt486 not Assessed for PRA; October 8, 2010
- CAP 1253510; Fifteen Inch Tear in Penetration 1689 Boot at G Wall; October 9, 2010
- CAP 1253509; Possible Fretting on Unit 2 Hydrogen Piping; October 9, 2010
- CAP 1253535; Feedwater Flow Swings Causing Thermal Power Monitor Oscillations; October 10, 2010
- CAP 1253513; Loose Bolts on Restraints for Main Steam Supply to Unit 2 Turbine; October 9, 2010
- CAP 1253948; Extended Delay in Planning WO for Failed Instrumentation and Controls Equipment; October 13, 2010
- CAP 1256883; Three Statements in 2009 MUR Submittal Not Properly Validated; November 2, 2010
- Alarm Response Procedure C47041; LEFM System Status; Revision 12
- Engineering Change 13597; Emergency Operating Procedure Setpoint Calculation Changes to Resolve Several CAPs and MUR Project Changes; Revision 1
- Engineering Change 547; Implementation of the PINGP Unit 1 and Unit 2 Measurement Uncertainty Recapture Uprate (05FW02 Part B); Revision 0
- FP-G-DOC-03; Procedure Use and Adherence; Revision 9
- 5AWI 15.1.5; Work Planning; Revision 6
- WO 373588; Unplug/Repair Bus Room 111 Cooler Drain Valve and Piping; August 31, 2010
- WO 108888; Repair/Replace Valve And Associated Thermostat CV-31755; August 31, 2010
- FP-WM-PLA-01; Work Order Planning Process; Revision 8
- FP-WM-PLA-01; Work Order Planning Process; Revision 9

- CAP 1247908; Unable To Perform Work On Switchgear Unit Cooler; August 31, 2010
- CE 1247908; Unable To Perform Work On Switchgear Unit Cooler; October 4, 2010
- EC 547; Implementation of the PINGP Unit 1 and Unit 2 Measurement Uncertainty Recapture (MUR) Uprate; Revision 0
- 10 CFR 50.59 Screening No. 3423; Implementation of the PINGP Unit 1 and Unit 2 Measurement Uncertainty Recapture (MUR) Uprate; Revision 2

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
CAP	Corrective Action Program
CDBI	Component Design Basis Inspection
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CL	Cooling Water
DDCLP	Diesel Driven Cooling Water Pump
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
ERCS	Emergency Response Computer System
FOTP	Fuel Oil Transfer Pump
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MDCLP	Motor Driven Cooling Water Pump
MSPI	Mitigating Systems Performance Indicator
MUR	Measurement Uncertainty Recapture
MWt	Megawatts Thermal
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-Licensed Operator
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OPR	Operability Recommendation
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
PLC	Programmable Logic Controllers
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SDP	Significance Determination Process
SP	Surveillance Procedure
SPAR	Simplified Plant Analysis Risk
SR	Surveillance Requirement
SRA	Senior Reactor Analyst
SSC	Structures, Systems, and Components
TS	Technical Specification
USAR	Updated Safety Analysis Report
URI	Unresolved Item
WO	Work Order
WR	Work Request

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Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000282/2010005; 05000306/2010005
w/Attachment: Supplemental Information

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Letter to M. Schimmel from J. Giessner dated January 31, 2011.

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000282/2010005; 05000306/2010005 AND INSPECTION OF MEASUREMENT UNCERTAINTY RECAPTURE POWER UPRATE ACTIVITIES

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