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

February 10, 2009

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

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2008005; 05000306/2008005

Dear Mr. Wadley:

On December 31, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on January 8, 2009, with you and other members of your staff.

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

Based on the results of this inspection, two NRC-identified and three 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 (NCV) in accordance with Section VI.A.1 of the NRC Enforcement Policy. Additionally, a licensee identified violation is listed in Section 4OA7 of this report.

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

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000282/2008005; 05000306/2008005
w/Attachment: Supplemental Information

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

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Letter to M. Wadley from J. Giessner dated February 10, 2009

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000282/2008005; 05000306/2008005

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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:	05000282/2008005; 05000306/2008005
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, 2008
Inspectors:	K. Stoedter, Senior Resident Inspector P. Zurawski, Resident Inspector T. Bilik, Reactor Inspector L. Haeg, Resident Inspector – Monticello R. Jickling, Senior Emergency Preparedness Inspector D. McNeil, Senior Operations Engineer G. O’Dwyer, Reactor Inspector R. Winter, Reactor Inspector
Approved by:	J. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000282/2008005, 05000306/2008005; 10/1/2008 – 12/31/2008; Prairie Island Nuclear Generating Plant, Units 1 & 2; Inservice Inspection, Refueling and Outages, Surveillance Testing, and Event Follow-up.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Five Green findings were documented by the inspectors. The findings were considered Non-Cited Violations (NCVs) 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: Initiating Events

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, in September 2008 for the failure of contractor welders to adhere to welding procedures during structural weld overlay (SWOL) repairs on a pressurizer surge nozzle. A review of the weld records indicated that the welders either failed to utilize the correct travel speeds in performing the SWOL or to accurately document relative travel speed settings as required by procedure, in order to ensure that the correct heat input (a welding essential variable) was maintained. The inspectors also identified that the welders failed to input the correct welding parameters into the welding controller for a portion of the overlay as required by procedure. This resulted in the heat input parameters being exceeded. Corrective actions for this issue included the removal and repair of the weld.

  This finding was more than minor because if left uncorrected, it would have become a more significant safety concern. Specifically, the failure to control the heat input could have reduced the impact toughness of the pressurizer weldment such that it would be susceptible to brittle fracture. The finding was of very low safety significance (Green) because the contractor subsequently addressed the programmed versus actual travel speed discrepancies and determined that the resulting heat inputs were bound by the welding procedure specifications' (WPS) parameters. Furthermore, the contractor repaired the surge nozzle as a result of using the incorrect welding parameters before returning Unit 2 to service. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel failed to ensure supervisory and management oversight of contractor activities such that nuclear safety was supported (H.4(c)). (Section 1R08.1)

- Green. One self-revealed finding of very low safety significance and an associated NCV of Technical Specification (TS) 5.4.1 was identified on October 13, 2008, due to an operator's failure to follow procedures during refueling activities. The failure to follow procedures resulted in a loss of seal injection flow to the 11 reactor coolant pump due to the manipulation of a Unit 1 seal injection valve rather than a Unit 2 seal injection valve. Corrective actions for this issue included communicating this event to all Operations personnel, resetting the operations department's event free clock and providing additional training of the use of human performance tools.

The inspectors determined that this finding was more than minor because if left uncorrected, a continued failure to follow procedures could lead to the incorrect operation of additional plant equipment and become a more significant safety concern. The inspectors determined that this issue was of very low safety significance because the finding would not result in leakage that exceeded any TS limit and because the finding would not have affected other mitigation equipment. Specifically, the reactor coolant pumps were designed to be able to operate without seal injection flow for several hours as long as the component cooling water supply to the thermal barrier heat exchanger remained within allowable ranges. The inspectors concluded that this finding was cross-cutting in the Human Performance, Decision Making area because the operator failed to use the systematic process for implementing procedures when deciding which valve needed to be manipulated (H.1(a)). (Section 1R20.1)

- Green. A finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V, was self-revealed on November 6, 2008, due to instrumentation and controls technicians failing to follow procedures during calibration of the power range nuclear instruments. The failure to follow procedures resulted in the uncontrolled movement of the Unit 2 control rods and a six percent reduction in reactor power. Corrective actions for this issue included removing the technicians' qualifications, conducting remedial training, performing a site-wide stand down to reinforce procedure use and adherence, and providing additional oversight of control room activities for several days.

  The inspectors determined that the finding was more than minor because it caused a plant transient and if left uncorrected, it would become a more significant safety concern that could result in additional plant transients, testing errors, and the failure to properly operate equipment. The inspectors determined that this finding was of very low safety significance because it did not contribute to both the likelihood of a reactor trip and that mitigating systems equipment would not be available. The inspectors concluded that this finding was cross-cutting in the Human Performance, Decision Making area because the technicians failed to use the systematic process for implementing procedures to ensure that nuclear safety was maintained (H.1(a)). (Section 1R22.1)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix R, Section J, on December 30, 2008, due to the licensee's failure to ensure that an alternate safe shutdown access path was provided with emergency lighting units that contained at least an 8-hour battery power supply. Corrective actions for this issue included ensuring that all personnel on-shift were respirator qualified so that alternate safe shutdown access pathways would not need to be used.

  The inspectors determined that this issue was more than minor because if left uncorrected, the failure to properly evaluate alternative safe shutdown access paths against regulatory requirements could become a more significant safety concern due to its potential impact on safely shutting down the plant following a fire. The inspectors determined that this finding was of very low safety significance due to its low exposure time and low degradation rating. The inspectors concluded that this finding was cross-cutting in the Human Performance, Decision Making area because the licensee failed to make this safety-significant/risk-significant decision using a systematic process that included a review of the safe shutdown analysis timeline and input from fire protection personnel (H.1(a)). (Section 4OA3.4)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and an associated NCV of TS 5.4.1 was self-revealed on October 9, 2008, due to the failure of contractor staff to follow procedures during refueling activities. This failure to follow procedures resulted in the insertion of a plug in a local leak rate testing port on the fuel transfer tube flange. The plug subsequently contacted a control rod located in a new fuel assembly and damaged the control rod while lifting the fuel assembly to a vertical position. Corrective actions for this issue included removing the plug, inspecting the fuel bundle and refueling equipment for damage, verifying the clearances between the fuel transfer tube flange and the upender basket, establishing a minimum design clearance between the fuel transfer tube flange and the top of a control rod, and using underwater cameras to ensure that clearances were maintained during fuel movement activities.

  The inspectors determined that this finding was more than minor because if left uncorrected, the failure to follow procedures during refueling activities could lead to the unknown installation of other equipment and increase the potential of damaging reactor fuel and/or plant equipment; therefore become a more significant safety concern. The inspectors reviewed IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," and determined that this type of finding was unable to be evaluated using this Appendix. As a result, the inspectors submitted the finding for management evaluation using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria." NRC Management reviewed the details of this issue and concluded that this finding was of very low safety significance because the insertion of the plug, and the subsequent contact between the plug and the control rod, did not result in damage to irradiated fuel. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the licensee failed to ensure supervisory and management oversight of work activities, including contractors, was maintained such that nuclear safety was supported (H.4(c)). (Section 1R20.1)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Operations personnel operated Unit 1 at or near full power until October 30, 2008, when reactor power was reduced to 95 percent to allow maintenance on the heater drain system. Operations personnel returned the reactor to full power levels on October 31, 2008. Additional power reductions were performed during the period to allow for routine testing and maintenance of plant components.

Unit 2 began the inspection period in Refueling Outage 2R25. The licensee entered Mode 2 at 9:56 a.m. on October 30, 2008. Approximately 4.5 hours later, operations personnel inserted a manual reactor trip in response to an urgent rod control failure that occurred during low power physics testing. Subsequent troubleshooting determined that the urgent failure occurred due to a random fuse failure. Operations personnel re-started Unit 2 on October 31, 2008. The main generator was synchronized with the electrical grid on November 1, 2008. From November 1 through November 8, the licensee conducted power ascension activities and testing of the new digital electro hydraulic control system. Unit 2 reached full power operating levels on November 8, 2008. A short time later, the licensee identified inconsistencies in the reactor power indication provided by the leading edge flow meter. Operations personnel lowered Unit 2 reactor power to 98.5 percent to ensure that reactor power remained below the licensed power level. On November 14, 2008, operations personnel lowered Unit 2 reactor power to 65 percent to conduct digital electro hydraulic control system tuning. Unit 2 returned to 98.5 percent power on November 15, 2008. The licensee resolved the reactor power indication inconsistencies and returned Unit 2 to 100 percent power on December 1, 2008. Unit 2 remained at this power level through the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's cold weather preparations to verify that the plant's design features were adequately protected from the effects of adverse weather. The inspectors reviewed the Updated Safety Analysis Report (USAR) and procedures for the selected systems to verify that all system performance requirements were adequately reflected in the system operating procedures. The inspectors also reviewed abnormal operating procedures to ensure that these procedures addressed the actions to be taken in response to potential cold weather issues. 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 station corrective action procedures. Specific documents reviewed during this inspection are listed in the

Attachment. The inspectors' review focused on the following plant systems due to their risk-significance or susceptibility to cold weather issues:

- Screenhouse Fire Protection;
- Condensate Storage Tanks; and
- D5 and D6 Emergency Diesel Generators.

This inspection constituted one seasonal readiness 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:

- 121 Safeguards Chilled Water System while the 122 Safeguards Chilled Water System was out of service;
- 22 Component Cooling Water System while the 21 Component Cooling Water Heat Exchanger was out of service;
- Bus 15 while the 22 Diesel-driven Cooling Water Pump was out of service; and
- 12 Diesel-driven Cooling Water Pump while the 22 Diesel-driven Cooling Water Pump was out of service.

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

These activities constituted four partial system walkdown samples 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 the availability, accessibility, and condition of firefighting equipment in the following risk-significant areas:

- Bus 15 and 16 Switchgear Rooms (Fire Areas 20 and 81);
- Bus 25, 26, and 27 Switchgear Rooms (Fire Areas 99, 109, and 110);
- Bus 111 Switchgear Room (Fire Area 22);
- Control Room (Fire Zone 57); and
- Auxiliary Building Mezzanine Elevator Area (Fire Zone 108).

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

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

From September 24 through October 3, 2008, the inspectors reviewed the licensee's Inservice Inspection (ISI) Program implementation for Unit 2. The ISI program was used to monitor potential degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, 1R08.4 and 1R08.5 constituted one inspection sample as defined in IP 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors observed the following nondestructive examinations (NDE) required by the American Society of Mechanical Engineers (ASME) Code, Section XI to evaluate compliance with the ASME Code, Section XI and Section V requirements. If indications and defects were detected, the inspectors reviewed the resolution of the indications and defects to determine that they were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic examination (UT) of reactor coolant system pipe-to-elbow weld (W-6);
- UT of reactor coolant system elbow-to-pipe weld (W-7);
- UT of safety injection (SI) system pipe-to-elbow weld (W-8); and
- UT of SI system piping weld (W-9).

The inspectors reviewed a record of the following NDE required by the ASME Code, Section XI to evaluate compliance with the ASME Code, Section XI and Section V requirements. The inspectors also observed activities and reviewed documents regarding any indications and/or defects to ensure that they were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Dye Penetrant examination of a containment integral attachment weld (H-1/IA).

The licensee did not identify surface or volumetric examinations completed during the previous outage with relevant/recordable conditions/indications accepted for continued service. Therefore, no NRC review was completed for this inspection attribute. The inspectors observed fabrication of the following pressure boundary weld (overlay repair) completed for pressure boundary risk-significant systems during Refueling Outage 2R25. The inspectors also reviewed weld related documents to determine if the licensee applied the pre-service NDE and acceptance criteria required by the Construction Code and NRC approved relief request 2-RR-4-8.

- Weld overlay repair of the pressurizer surge nozzle-to-safe end weld (W-17).

The inspectors reviewed the following pressure boundary weld completed for risk-significant systems since the beginning of the last refueling outage to verify that the welding and any associated NDEs were performed in accordance with the Construction Code and the ASME Code, Section XI.

- Seal weld repair of the boric acid filter to reactor makeup emergency boration check valve (2VC-8-15).

The inspectors also reviewed the welding procedure specification and supporting weld procedure qualification records for the activity above, to determine if the welding procedures were qualified in accordance with the requirements of the Construction Code and the ASME Code, Section IX.

b. Findings

Failure to Follow Welding Procedures

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure of contractor welders to adhere to welding procedures during the structural weld overlay (SWOL) repairs on a pressurizer surge nozzle.

Description: On October 1, 2008, while reviewing weld control records (WCR) for machine gas tungsten arc welding (GTAW) of the SWOL on the pressurizer surge nozzle dissimilar metal weld as part of the licensee's Alloy 600 mitigation program, the inspectors observed that the documented weld speed had not been changing as required by procedure. The speed change, which corresponded to a change in piping/nozzle diameter, was required by all of the welding procedure specifications (WPS) used to apply the SWOL in order to maintain a constant required travel speed. While addressing the weld speed issue, it was subsequently discovered that incorrect welding parameters had been used to apply layer one of the temper bead weld over a portion of the ferritic nozzle material.

The primary WPS used for the pressurizer surge nozzle SWOL weld records being reviewed was "55WP1/8/43/F43OLTBSCa3." Operating Instruction (OI) 55-OI0069-000, a supplement to the WPS, provided instructions on the techniques to be used in performing a SWOL with the machine GTAW process using the ambient temperature temper bead technique. To control the weld heat input (an essential welding variable), it was necessary to control the weld head travel speed. The OI indicated that the travel speed (one component of heat input) was to be established by cross-referencing the radius and the desired travel speed (i.e., the speed as measured at the tungsten weld tip) to obtain the travel speed which needed to be programmed into the welding machine. In order for the speed at the tungsten to remain constant as required to control heat input, the parameters the welders input to control weld head speed for each layer were established and provided to the welders in Table 1 of the OI.

The OI indicated that it was imperative that the heat input as specified in the WPS not be violated and that the parameters for each layer were required be recorded on a WCR. Furthermore, that OI stated that any changes made to the weld parameters must be verified by the Weld Supervisor and required entry on the WCR. The OI further stated that the Welding Supervisor must verify first layer weld parameters prior to arc initiation and verify by calculation that the heat input range and other mandatory requirements would not be violated.

The inspectors observed through review of the WCRs that the travel speed programmed into the welder controller, which should have been changing as previously discussed, had remained constant for the welding performed over several sections of the SWOL. As a result, it was impossible to tell from the documentation (which had been reviewed and signed off by weld supervisor), whether the actual travel speed used was incorrect, or whether the documentation was incorrect, and therefore it could not be confirmed at that point that the heat input to the SWOL had been controlled in accordance with the procedure. The inspectors notified the welding supervisor who concurred with the inspectors' observations and stopped welding activities. The vendor sent the WCRs off-site for review to determine whether the travel speeds programmed over the range of diameters overlaid had or had not caused a violation of the heat input parameters. While reviewing the WCRs, it was further discovered that the first layer temper bead weld had been incorrectly applied over a section of the ferritic nozzle adjacent to a stainless steel butter interface. The welders had failed to change settings when transitioning from the butter to the nozzle.

The review of the WCRs identified two WCRs that contained errors in the travel speed. It was determined that heat inputs associated with the WCR travel speeds were bound by the heat input range qualified but that the errors associated with the incorrect temper bead parameters were not. The heat input on the nozzle exceeded that allowed by the WPS. The weld was removed (ground out) and the pipe was re-welded.

The contractor issued AREVA corrective action document CR 2008-5336 to address the two issues discussed above. The licensee documented these issues in CAP 1153576.

<u>Analysis</u>: The inspectors determined that the failure of the contractor welders to adhere to procedures in order to adequately control heat input was a performance deficiency warranting a significance determination. This finding was more than minor because if left uncorrected, it would have become a more significant safety concern. Specifically, the failure to control heat input could have reduced the impact toughness of the pressurizer weldment such that it would be susceptible to brittle fracture. The finding affected the Initiating Events Cornerstone. The finding is of very low safety significance (Green) because it was subsequently determined through calculations that the resulting heat inputs, in those cases where travel speed was in question, were bound by the WPS parameters. Furthermore, in the case where the welders failed to use the correct temper bead welding parameters, the weld material was ground out and repaired. Because the evaluation and the repairs were made prior to returning Unit 2 to service, it was unlikely that there would be reactor coolant system leakage or the loss of safety function of any mitigating system; and therefore screens out as Green using the phase 1 worksheet question 1. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because licensee personnel failed to ensure supervisory and management oversight activities of their contractors such that nuclear safety was supported (H.4(c)).

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures.

The application of a SWOL over the pressurizer surge nozzle to form a new pressure boundary using "WPS 55WP1/8/43/F43OLTBSCa3 (the weld overlay procedure containing the heat input and welding parameters for ambient temper bead welding)," is an activity affecting the quality of the component's safety-related function to serve as part of the reactor coolant pressure boundary.

Operating Instruction (OI) 55-OI0069-000 provided instructions on the techniques to be used in performing a SWOL with the machine GTAW process using the ambient temperature temper bead technique. Section 6.3.1 of the OI stated that, “It is imperative that the heat input as specified in the WPS not be violated. Weld Supervisors shall verify all parameters prior to the start of each welding layer. The parameters for each layer shall be recorded on a WCR. Any changes to the weld parameters must be verified by the Weld Supervisor prior to welding and require entry on the Contract Specific WCR.”

Section 6.5.2.1, “First Layer Temperbead Welding with ERNiCrFe-7A,” stated that, “The Welding Supervisor must verify first layer weld parameters prior to arc initiation and verify by calculation that the heat input range and other mandatory requirements in Section 11.0, “Weld Overlay Parameters,” will not be violated.”

Contrary to the above, on October 1, 2008, the application of a SWOL over the pressurizer surge nozzle to form a new pressure boundary, an activity affecting quality, was not accomplished in accordance with procedures. Specifically, while welding over an area where the diameters of the underlying material changed, the welders failed to ensure that the heat input and other mandatory requirements as specified in the WPS and directed by the OI were not violated. Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program as CAP 1153576, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000306/2008005-01)**. Corrective actions for this issue included the removal and repair of the weld.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 2 vessel head, no examination was required pursuant to NRC Order EA-03-009 and the licensee did not complete one during the current refueling outage. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control

a. Inspection Scope

The inspectors observed the licensee’s boric acid corrosion control visual examinations for portions of the reactor coolant and/or emergency core cooling systems within containment to determine if these visual examinations emphasized locations where boric acid leaks can cause degradation of safety significant components. The inspectors reviewed the following licensee evaluations of reactor coolant system components with boric acid deposits to determine if degraded components were documented in the corrective action system. The inspectors also evaluated corrective actions for any degraded reactor coolant system components to determine if they met the licensee’s boric acid program procedures and the ASME Code, Section XI.

- Sump B to 22 Residual Heat Removal (RHR) Pump Train B Motor Valve (MV-32181); and
- 22 Reactor Coolant Pump Seal Water Outlet Isolation Control Valve (CV-31427).

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

- Work Order (WO) 1128864, Valve VC-42-3 Has a Packing Leak; and
- WO 1065208, Motor Valve MV-32183 Boric Acid on ASME Body to Bonnet Stud.

b. <u>Findings</u>

No findings of significance were identified.

.4 <u>Steam Generator Tube Inspection Activities</u>

a. <u>Inspection Scope</u>

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

- in-situ SG tube pressure testing screening criteria used were consistent with those identified in the Electric Power Research Institute TR-1014983, Steam Generator In-Situ Pressure Test Guidelines and that these criteria were properly applied to screen degraded SG tubes for in-situ pressure testing;
- the numbers and sizes of SG tube flaws/degradation identified were bound by the licensee's previous outage Operational Assessment predictions;
- the SG tube ET examination scope and expansion criteria were sufficient to meet the TS and Electric Power Research Institute Document 1013706, Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 7;
- the SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to these SG tubes;
- the licensee identified new tube degradation mechanisms and implemented adequate extent of condition inspection scope and repairs for the new tube degradation mechanism;
- the licensee implemented repair methods which were consistent with the repair processes allowed in the TS requirements and to determine if qualified depth sizing methods were applied to degraded tubes accepted for continued service;
- the licensee implemented an inappropriate "plug on detection" tube repair threshold (e.g., no attempt at sizing of flaws to confirm tube integrity);
- the licensee's primary-to-secondary leakage (e.g., SG tube leakage) was below three gallons-per-day or the detection threshold during the previous operating cycle;
- the ET probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for

Eddy Current Examination, of Electric Power Research Institute Document 1013706, Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 7;

- the licensee performed secondary side SG inspections for location and removal of foreign materials; and
- the licensee implemented repairs for SG tubes damaged by foreign material. The licensee did not perform in-situ pressure testing of SG tubes. Therefore, no NRC review was completed for this inspection attribute.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the corrective action program and conducted interviews with licensee staff to determine if:

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

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

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 18, 2008, the inspectors observed a crew of licensed operators in the simulator during licensed operator requalification examinations to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was conducted in accordance with procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of alarms;

- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

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

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results (71111.11B)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the biennial written examination, 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 November 2008 through December 2008 as part of the operator licensing requalification cycle. These results were compared to the thresholds established in IMC 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 IP 71111.11, "Licensed Operator Requalification Program." The documents reviewed during this inspection are listed in the Attachment.

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Direct Current System and
- Cooling Water System.

The inspectors reviewed events where ineffective maintenance had resulted in valid or invalid automatic actuations of 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/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

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

b. Findings

No findings of significance were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Irradiated fuel handling with 122 Control Room Chiller inoperable; and
- Emergent work on the 21 RHR system.

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

These maintenance risk assessments and emergent work control activities constituted two 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:

- Bus 15 Load Sequencer operability following the receipt of Error Code 103 messages during surveillance testing;
- Potential incorrect parts installed on the Unit 1 Pressurizer Safety Relief Valve RC-10-1 and RC-10-2 gaskets;
- Potential breaker coordination issues between safety-related and non-safety-related event monitoring components;
- Pinhole leak on Safeguards Chilled Water Line 3-ZH-2;
- Unit 1 Component Cooling Water high energy line break concern; and
- Unit 2 Component Cooling Water high energy line break concern.

The inspectors selected these potential operability issues for review 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 operable or functional such that no unrecognized increase in risk occurred. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

Introduction: One unresolved item (URI) was identified due to the potential interaction between high energy piping in the turbine building and component cooling water (CCW) piping to the chemistry cold lab.

Description: On July 29, 2008, the licensee initiated CAP 1145695 to document that CCW piping located in the turbine building, and used to supply water to the chemistry cold lab, passed directly underneath high energy piping from the 15A and 15B feedwater heaters. As part of the CAP review, operations personnel requested that an operability review be completed to evaluate the impact that a failure of this high energy piping could have on the continued operability of the CCW system. The licensee initially determined that a failure of this piping would have some impact on the Unit 2 CCW system because the 2A train of CCW normally supplied water to the chemistry cold lab. There was no impact on the operation of the Unit 1 CCW system. As a result, this condition was expected to have little impact on overall plant operation because each unit maintained its ability to achieve its required operating condition following a Unit 1 high energy piping failure.

Over the next few days, the licensee continued to review the high energy and CCW piping configurations in the Unit 1 and Unit 2 turbine buildings. On July 31, 2008, the licensee identified that a failure in a Unit 2 turbine building high energy line could impact the continued operability of the Unit 2 CCW system. The licensee conducted an operability review and determined that the Unit 2 CCW system was inoperable due to the potential interaction between the Unit 2 turbine building high energy piping and the Unit 2 CCW system. The licensee also determined that the operators' ability to bring Unit 2 to a cold shutdown condition following this type of piping failure may be impacted. Operations personnel immediately entered TS 3.0.3 to address this concern. The operators closed several valves in the CCW system to isolate the CCW piping in the turbine building from the other CCW piping. By closing these valves, operations personnel eliminated the potential that the Unit 2 CCW system would become inoperable following a Unit 2 turbine building high energy piping failure. The Unit 2 CCW system was restored to an operable status following the valve closures. The CCW piping to the turbine building remained isolated at the conclusion of the inspection period.

At the conclusion of the inspection period, the inspectors were reviewing the high energy and CCW piping configurations in the Unit 1 and Unit 2 turbine buildings to ensure that the piping failures discussed in the licensee's CAP documents and Licensee Event Report (LER) 05000306/2008-01 were the most limiting locations. In addition, the inspectors were waiting for information regarding the actual times that each unit's CCW system was aligned to the chemistry cold lab to determine whether the impacts of a Unit 1 high energy piping failure on the continued operability of the Unit 1 CCW system and the shutdown cooling function of the RHR system needed further review. Finally, the inspectors needed to review several older CAPs and operating experience related to the issue to determine whether the issue was within the licensee's ability to foresee and correct (i.e., is it a performance deficiency). As a result, this item was considered unresolved pending the receipt and review of the above information **(URI 05000306/2008005-02)**.

1R18 <u>Plant Modifications</u> (71111.18)

.1 <u>Temporary Plant Modifications</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the following temporary modification:

- Engineering Change 13438 – Recurring Temporary Modification for Additional Cooling Water Flow.

The inspectors compared the temporary configuration change and associated 10 CFR 50.59 screening 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(s). 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 operated as expected and that 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.

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

b. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The following engineering design package was reviewed and selected aspects were discussed with engineering personnel:

- Safety Injection Check Valves SI-9-1 through 6 and 2SI-9-1 through 6 Hanger Bracket, Dowel Pin, and Disc Pin Retainer Changes.

This engineering design package and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and to ensure that relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents.

This inspection constituted one permanent plant 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 activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- SP 2092D, Safety Injection Check Valve Test (Head On) Part D: Low Head SI Discharge Flow Path Verification (Routine); Revision 9;
- SP 1194, Cardox (Carbon Dioxide) 18 Month System Test, Revision 18;
- SP 2102, 22 Turbine-driven Auxiliary Feedwater (AFW) Pump Monthly Test, Revision 84;
- SP 1094, Bus 15 Load Sequencer Test, Revision 23;
- SP 2089B, Train B RHR Pumps and Suction Valves from the Refueling Water Storage Tank Quarterly Test, Revision 13; and
- SP 1106B, 22 Diesel Cooling Water Pump Monthly Test, Revision 72.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion), and test documentation was properly evaluated. The inspectors evaluated the activities against 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 testing to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

During this inspection period, the inspectors continued their review of outage activities for Refueling Outage 2R25 which began on September 19, 2008. During the refueling outage, the inspectors monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including maintenance of defense-in-depth for key safety functions and compliance with the applicable TS when taking equipment out-of-service;
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;

- Controls over the status and configuration of electrical systems to ensure that TS requirements were met;
- Monitoring of decay heat removal processes, systems, and components;
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- Controls over activities that could affect reactivity;
- Maintenance of secondary containment as required by TS;
- Refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- Licensee identification and resolution of problems related to refueling activities.

This inspection was considered a partial inspection sample. Credited along with Integrated Inspection Report (IR) 05000282/2008004; 05000306/2008004, this is one full sample.

Documents reviewed during the inspection are listed in the Attachment to this report.

b. Findings

(1) Failure to Follow Procedure Results in Damage to Control Rod

Introduction: One self-revealing (Green) finding and an associated NCV of TS 5.4.1 was identified due to the failure of contractor staff to follow procedures during refueling activities. This failure to follow procedures resulted in the insertion of a plug in a local leak rate testing (LLRT) port on the fuel transfer tube flange. The plug subsequently contacted a control rod located in a new fuel assembly and damaged the control rod while lifting the fuel assembly to a vertical position.

Description: Refueling Outage 2R25 began on September 18, 2008. Following the plant shut down, the licensee utilized contractors to prepare the reactor vessel and refueling area for refueling activities using Procedure 2D3, “Unit 2 Reactor Vessel Head Removal.” Section 7.3.5 of Procedure 2D3 was used to prepare the refueling pool area. Contractor personnel proceeded through the first three steps of Section 7.3.5 as written. However, contractors then inserted a brass plug into the LLRT port located at the 12 o’clock position on the fuel transfer tube flange. Although the contractors’ training included the plug installation, the installation was not discussed in Procedure 2D3. In addition, contractor personnel failed to initiate a procedure change as discussed in Procedures FP-G-DOC-03, “Procedure Use and Adherence,” and FP-G-DOC-04, “Procedure Change Process,” to allow the plug installation. Lastly, the licensee was not informed of, nor aware of, the plug’s installation due to weak oversight of contractor activities. Following the plug’s installation, Procedure 2D3 was completed as written. Contractor personnel completed a full core offload without incident.

On October 9, 2008, contractor personnel began re-loading the fuel assemblies into the reactor core. Thirteen fuel assemblies, which did not contain control rods, were successfully re-loaded. The contractors encountered difficulty when trying to latch onto the 14th fuel assembly with the manipulator crane (this was the first assembly to be re-loaded that contained a control rod). During a subsequent review, the licensee determined that the manipulator crane could not latch onto the fuel assembly because the control rod inserted in the fuel assembly had come into contact with the brass plug inserted in the flange. The contact between these two points resulted in bending the control rod approximately 5 to 10 degrees. The licensee conducted troubleshooting activities and was able to remove the control rod from the fuel assembly. Although the control rod was unable to be repaired, the licensee performed additional inspections of the fuel assembly and determined that the assembly was acceptable for use.

Analysis: The inspectors determined that the failure of the contractor personnel to follow Procedure 2D3 was a performance deficiency requiring an evaluation using the Significance Determination Process. The inspectors determined that this finding was more than minor because if left uncorrected, the failure to follow procedures during refueling activities could lead to the unknown installation of other equipment and increase the potential of damaging reactor fuel and/or plant equipment, a more significant safety concern. The finding affected the Barrier Integrity Cornerstone for the fuel barrier. The inspectors reviewed IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," and determined that this type of finding was unable to be evaluated using this Appendix. As a result, the inspectors submitted the finding for management evaluation using IMC 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria." NRC Management reviewed the information provided above and concluded that this finding was of very low safety significance (Green) because the insertion of the plug, and the subsequent contact between the plug and the control rod, did not result in damage to any irradiated fuel. The fuel bundle was new fuel. The inspectors determined that this finding was cross-cutting in the Human Performance, Work Practices area because the licensee failed to ensure supervisory and management oversight of work activities, including contractors, was maintained such that nuclear safety was supported (H.4(c)).

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

Section 1.k of Regulatory Guide 1.33, Revision 2, Appendix A requires that written procedures be established, implemented, and maintained for activities associated with the preparation for refueling and refueling equipment operation.

Section 7.3.5 of Procedure 2D3, "Unit 2 Reactor Vessel Head Removal," provided instructions for preparing the refueling pool area for refueling activities. In addition, Section 7.3.5 of Procedure 2D3 did not establish instructions for inserting a plug into a LLRT port as part of the licensee's normal refueling preparation activities.

Contrary to the above, on October 9, 2008, contractor personnel failed to implement the requirements of Procedure 2D3 during the preparation for refueling. Specifically, contractor personnel inserted a plug into a LLRT port which was contrary to the instructions provided in Procedure 2D3. During the subsequent movement of a new fuel assembly containing a control rod, the control rod contacted the plug. This contact resulted in bending the control rod 5 to 10 degrees. The control rod was unable to be used. However, because this violation is of very low safety significance (Green) and was entered into your corrective action program as CAP 1154696, it was treated as an NCV consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000306/200800-03)**. Corrective actions for this issue included removing the plug, inspecting the fuel assembly and refueling equipment for damage, manually lowering multiple fuel assemblies containing control rods to verify the clearances between the fuel transfer tube flange and the upender basket, establishing a minimum design clearance between the fuel transfer tube flange and the top of a control rod, and using underwater cameras to ensure that clearances were maintained during fuel movement activities.

(2) Manipulation of Incorrect Valve Results in Loss of 11 Reactor Coolant Pump Seal Injection

Introduction: One self-revealing finding of very low safety significance (Green) and an associated NCV of TS 5.4.1 was identified due to an operator's failure to follow procedures during refueling activities. The failure to follow procedures resulted in a loss of seal injection flow to the 11 reactor coolant pump due to the manipulation of a Unit 1 seal injection valve rather than a Unit 2 seal injection valve.

Description: On October 13, 2008, operations personnel were performing Procedure 2C4.2, "Reactor Coolant System Inventory Control – Post Refueling." Step 5.1.9 of this procedure provided instructions for isolating reactor coolant pump seal injection by closing Reactor Coolant Pump Seal Injection Throttle Valves 2VC-14-1 and 2VC-14-2. However, the operator assigned to perform this activity closed Reactor Coolant Pump Seal Injection Throttle Valve VC-14-1. The operator immediately recognized his error and reopened Valve VC-14-1. The Unit 1 control room also received an alarm due to the decrease in seal injection flow. Although seal injection flow to the 11 Reactor Coolant Pump was lost momentarily, no damage to the pump occurred.

The inspectors reviewed the licensee's corrective action documents and the results of interviews held following this event. The inspectors determined that operator encountered several items that should have caused him to stop and re-orient himself to the task to be performed. These factors included:

- The operator was distracted by other plant workers while walking to the valve location.
- Due to plant conditions, the operator expected to find valve 2VC-14-1 in the closed position. The operator failed to stop and ask for assistance when he found valve VC-14-1 in the open position.
- The operator noted that the area that he walked to was very noisy. The operator expected the area to be quiet since Unit 2 was in a shut down condition.

In addition, the inspectors determined that the operator failed to adequately verify that the valve label matched the valve number in Step 5.1.9 of Procedure 2C4.2.

Analysis: The inspectors determined that the failure to follow Step 5.1.9 of Procedure 2C4.2 was a performance deficiency requiring an evaluation using the SDP. The inspectors determined that this finding was more than minor because if left uncorrected, the failure to follow procedures could lead to the incorrect operation of additional plant equipment and a more significant safety concern. The finding affected the Initiating Events Cornerstone. The inspectors performed a Phase 1 SDP Screening and determined that this issue was of very low safety significance (Green) because the finding would not result in leakage that exceeded any TS limit and because the finding would not have affected other mitigation equipment. Specifically, the reactor coolant pumps were designed to be able to operate without seal injection flow for several hours as long as the component cooling water supply to the thermal barrier heat exchanger remained within allowable ranges. The inspectors determined that this finding was cross-cutting in the area of Human Performance, Decision Making because the operator failed to use the licensee's systematic procedure implementation process when making the decision to operate the seal injection valve (H.1(a)).

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

Section 1.I of Regulatory Guide 1.33, Revision 2, Appendix A requires that written procedures be established, implemented, and maintained for activities associated with refueling.

Procedure 2C4.2, "Reactor Coolant System Inventory Control – Post Refueling," was a procedure used for refueling activities.

Step 5.1.9 of Procedure 2C4.2 required that the reactor coolant pump seal injection be isolated by closing Valves 2VC-14-1 and 2VC-14-2.

Contrary to the above, on October 13, 2008, operations personnel failed to properly implement Procedure 2C4.2 as required by Regulatory Guide 1.33 and TS 5.4.1. As a result, seal injection flow was isolated to the 11 Reactor Coolant Pump rather than the 21 Reactor Coolant Pump. However, because this violation is of very low safety significance and was entered into your corrective action program as CAP 1155146, it was treated as a NCV consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000282/2008005-04; 05000306/2008005-04)**. Corrective actions for this issue included communicating this event to all operations personnel, resetting the operations department's event free clock and providing additional training of the use of human performance tools.

.2 Review of Operating Experience Smart Sample FY2007-03, Revision 1, Crane and Heavy Lift Inspection, Supplemental Guidance for IP 71111.20

a. Inspection Scope

As part of the Unit 2 refueling outage, the inspectors performed a review of the licensee's containment polar crane heavy lift procedures and processes using the guidance of Operating Experience Smart Sample FY2007-03. The inspectors determined the following:

- The licensee's polar crane was not single failure proof;
- The licensee had a preventive maintenance and testing program for the crane. In addition, testing and inspection procedures were implemented prior to the crane being used;

- The licensee's reactor vessel head lift procedures conformed to an acceptable safety basis (the licensee's load drop analysis);
- The licensee's load drop analysis bounded their lifting procedures with regard to maximum lift height of the reactor vessel head over the reactor vessel. The load drop analysis specified a maximum lift height of 27 feet over the vessel flange while the lifting procedure limited the height to 26.75 feet;
- The load drop analysis had been updated to reflect any significant change in the weight of the heavy load to be lifted; and
- The load drop analysis bounded the lifting procedure with regard to the medium through which the drop would occur.

In addition to documentation reviews, the inspectors observed the initial Unit 2 head removal lift as well as the final head reinstallation. The inspectors verified that the height limitations were maintained during the lifts. Documents reviewed are listed in the Attachment to this report.

This inspection was considered part of the refueling outage sample discussed in Section 1R20.1 of this report and did not constitute a separate sample.

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 2095, Bus 26 Load Sequencer Test;
- SP 1722, Unit 1 Loop Delta T Check;
- SP 1090B, 12 Containment Spray Pump Quarterly Test; and
- SP 2318.3, Nuclear Instrumentation System Power Range Channel Calibration.

The inspectors observed in-plant activities and reviewed procedures and associated records to determine whether: any preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; plant equipment calibration was correct, accurate, and properly documented; as-left setpoints were within required ranges; and the calibration frequency were 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 of the ASME Code, and reference values were consistent with the system design basis; where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable; where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure; where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished; prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test; equipment was returned to a position or status required to support the performance of its safety functions; and all problems identified during the testing were appropriately documented and dispositioned in the CAP. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

(1) Failure to Follow Procedure Results in Control Rod Movement

Introduction: A finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion V was self-revealed due to instrumentation and controls (I&C) technicians failing to follow procedures during calibration of the power range nuclear instruments on November 6, 2008. The failure to follow procedures resulted in the uncontrolled movement of the Unit 2 control rods and a six percent reduction in reactor power.

Description: On November 6, 2008, I&C personnel were calibrating the nuclear instrumentation power range monitors using Surveillance Procedure (SP) 2318.3. Step 8.5.9 of SP 2318.3 required that the rod control system be placed in manual if the reactor was operating when the calibration was performed. In addition, SP 2318.3 required that Step 8.5.9 be signed by a member of the operations staff. Although Unit 2 was operating on November 6, 2008, the I&C technician decided that the rod control system was in manual because the system had been in that condition during the calibration of two other power range channels. The space for the operator to sign that Step 8.5.9 was complete was left blank. Immediately following the completion of the next procedure step, the Unit 2 control rods began inserting into the reactor core at maximum speed. Operations personnel placed the rod control system in manual and stopped the rod movement after verifying that all other plant conditions were normal. However, the failure to follow procedure and subsequent control rod movement resulted in a 6.5 degree Fahrenheit reduction in reactor coolant system average temperature, a 43 pound drop in pressurizer pressure, and a 6 percent drop in reactor power.

Analysis: The inspectors determined that the failure to follow procedures during calibration of the power range nuclear instruments was a performance deficiency that warranted a significance determination. The finding affected the Initiating Events Cornerstone. The inspectors determined that the finding was more than minor because it fits the more than minor example of IMC 0612 Appendix E.4.b in that the failure to follow procedure caused a transient (control rod movement). In addition, the inspectors determined that the finding was more than minor because it caused a plant transient and if left uncorrected, it would become a more significant safety concern that could result in additional plant transients, testing errors, and the failure to properly operate equipment.

The inspectors performed a Phase 1 SDP screening and determined that this finding was of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and that mitigating systems equipment would not be available. The inspectors determined that this finding was cross-cutting in the Human Performance, Decision Making area because the technicians failed to use the licensee's systematic procedure implementation process to ensure that nuclear safety was maintained (H.1(a)).

Enforcement: 10 CFR Part 50, Appendix B, Criterion V requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to the above, on November 6, 2008, I&C technicians failed to accomplish the calibration of Unit 2 power range nuclear instrumentation in accordance with SP 2318.3, "Nuclear Instrumentation System Power Range Channel Calibration." Specifically, Step 8.5.9 of SP 2318.3 required that operations personnel place the rod control system in manual if the associated reactor was at power. Although Unit 2 was at power on November 6, 2008, the I&C technicians failed to request that operations personnel place the rod control system in manual. This resulted in a subsequent plant transient. However, because this violation was of very low safety significance and was entered into your corrective action program as CAP 1158394, it was treated as an NCV consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000306/2008005-05)**. Corrective actions for this issue included removing the I&C technicians' qualifications, conducting remedial training, performing a site-wide stand down to reinforce procedure use and adherence, and providing additional oversight of control room activities for several days.

(2) Use of Abnormal Operating Procedure Following Uncontrolled Rod Motion

Introduction: One URI was identified regarding whether operations personnel should have entered Abnormal Operating Procedure (AOP) 1C5 AOP 2 on November 6, 2008 following unexpected Unit 2 control rods insertion into the core. This item remains unresolved pending the inspector's evaluation of whether the practices employed by the Prairie Island Operations staff of using a knowledge-based operating standard rather than using a process-based operating standard for transitioning into AOPs were in accordance with procedures and industry standards.

Description: On November 6, 2008, I&C technicians were calibrating power range nuclear instruments using SP 2318.3, "Nuclear Instrumentation System Power Range Channel Calibration." As discussed in the Section above, the I&C technicians failed to ensure that the rod control system was placed in manual prior to inserting a test signal into the instrument being calibrated. Immediately after the signal was inserted, the Unit 2 control rods began inserting into the core. After validating that all other plant parameters were normal, the Unit 2 control room operators placed the rod control system in manual to stop the control rod movement.

The following day, the inspectors reviewed Abnormal Operating Procedure 1C5 AOP 2. The inspectors found that several of the symptoms listed in the AOP were experienced during the unexpected control rod movement on November 6, 2008. Specifically, control room personnel experienced the following symptoms:

- Insertion of rods as shown by the step counters and/or rod position indicators;
- Decreasing nuclear instrumentation readings;
- Decreasing reactor coolant system average temperature; and
- Decreasing pressurizer pressure.

The inspectors questioned operations personnel to determine why 1C5 AOP 2 was not entered on November 6, 2008. The inspectors were informed that the AOP was not entered because the control room operators knew the cause of the rod movement (that is, that the rod movement was caused by the technician's error). The inspectors asked for a copy of any licensee procedure that allowed AOPs not to be entered if the cause of the entry condition was known. No procedures were provided to the inspectors.

The inspectors also had discussions with the licensee's operations training staff regarding how the licensed operators were trained to respond to AOP entry conditions and symptoms. The inspectors were provided with several training scenarios for review. Based upon the information found in the training scenarios, the inspectors determined that the current training methods fostered a philosophy that AOPs were not required to be entered if the cause of the entry condition/symptom was known. This concerned the inspectors as it seemed to allow operations personnel to transition into a knowledge based operating philosophy rather than a process based operating philosophy. At the conclusion of the inspection period, the licensee was contacting Westinghouse and other licensees to determine whether the practices employed by the Prairie Island Operations staff were outside of industry norms. As a result, this issue is considered unresolved pending the receipt and review of the industry information from the licensee **(URI 05000282/2008005-06; 05000306/2008005-06)**.

.2 Reactor Coolant System Leak Detection Inspection

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

- SP 2070, Reactor Coolant System Integrity Test

The inspectors reviewed procedures and associated records to determine whether: preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; 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, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable; 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 corrective action program. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one reactor coolant system leak detection inspection sample as defined in IP 71111.22.

.3 Inservice Testing Surveillance

a. Inspection Scope

The inspectors reviewed the test results for the following activity 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 2102, 22 Turbine-driven AFW Pump Monthly Test.

The inspectors observed activities and reviewed procedures and associated records to determine whether any preconditioning occurred; effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; plant equipment calibration was correct, accurate, and properly documented; as left setpoints were within required ranges; and the calibration frequency were 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 ASME Code, Section XI, 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 corrective action program. Documents reviewed were listed in the Attachment to this report.

This inspection constituted one IST sample as defined in IP 71111.22.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

.1 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

Since the last NRC inspection of this program area, Emergency Plan Revisions 37 and 38 and implementing procedure F3-2.1, "Emergency Action Level Technical Bases," Revision 2, were implemented based on your determination that the changes resulted in no decrease in effectiveness of the Plan, and that the revised Plan as changed continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level changes to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety.

This emergency action level and emergency plan changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Mitigating Systems Performance Index (MSPI) - RHR System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - RHR System performance indicators for Units 1 and 2 for the period from the fourth quarter 2007 through the third quarter 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, were used. The inspectors reviewed the licensee’s operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of September 2007 through September 2008 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 - 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 performance indicators for Units 1 and 2 for the period from the fourth quarter 2007 through the third quarter 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated Inspection Reports for the period of September 2007 through September 2008 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. 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: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the attached List of Documents Reviewed.

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

b. Findings

No findings of significance were identified.

.2 Daily Corrective Action Program Reviews

a. Scope

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

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

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above. The inspectors' review nominally considered the six month period of July 2008 through December 2008, although some examples expanded beyond those dates where the scope of the trend warranted. The review also included issues documented outside the normal CAP in major equipment problem lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports and self assessment reports.

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

b. Observations

The inspectors determined that an adverse trend in the licensee's ability to promptly identify and/or thoroughly evaluate problems, first identified in June 2008, had continued. However, the inspector found that the licensee's failure to properly identify and/or evaluate issues appeared to be tied to a weakness in procedure use and adherence. The specific examples are as follows:

- On September 9, 2008, the licensee entered an unplanned Limiting Condition for Operation (LCO) due to miscommunication/qualifications. During the performance of a surveillance procedure on September 9, 2008, maintenance personnel and a LLRT engineer were working together to test the Unit 2 personnel airlock. The engineer left for the day prior to the end of the surveillance test. Maintenance personnel finished the test. After completion of the test, the control room was told they could exit the applicable TS LCO because the surveillance procedure had been completed satisfactorily. Approximately 1.5 hours later, the licensee discovered that a step that was required to be performed by a qualified LLRT engineer had actually been performed by maintenance personnel. The inspectors determined that an inadequate evaluation of the test resulted in inappropriately exiting the TS LCO. As a result, the TS LCO had to be re-entered until a qualified LLRT engineer could completed the procedure step. This issue was captured in the corrective action program via CAP 1150062. This was determined to be a minor violation of TS requirements.

- On September 22, 2008, operations personnel were establishing conditions to perform the integrated safety injection test. During the test preparations, the shutdown cooling function was provided by the 21 RHR system. In addition, the 21 SG was drained, the 21 AFW pump supply to the 22 SG was tagged closed and power was removed from the valve. The 21 AFW pump was also tagged with an information tag. At approximately 10:00 a.m., operations personnel identified that the reactor coolant system temperature was increasing. The licensee determined that the increased temperature was caused by an equipment failure within the 21 RHR system. Operations personnel immediately declared the 21 RHR system inoperable. The responsible senior reactor operators quickly determined the change in shutdown risk due to the equipment failure. However, operations personnel failed to include the status of the steam generators and the 21 AFW pump as part of the updated shutdown risk assessment for approximately 1.75 hours. This issue was captured in the corrective action program as CAP 1151611. This issue was determined to be a licensee-identified violation of 10 CFR 50.65(a)(4) that was documented in Section 4OA7 of this report.

- On September 26, 2008, NRC inspectors a reviewed welding activities conducted by the licensee. During these reviews, the inspector noted that an incorrect pre-clean drying time was used during a liquid penetrant examination of a seal weld. The procedure specified a minimum drying time of 5 minutes. The examination report recorded a drying time of 3 minutes. The inspectors determined that this issue had not been previously identified by the licensee due to inadequate procedure adherence and poor supervisory oversight. This issue was determined to be a minor violation of NRC requirements. In addition, the issue was captured in the corrective action program as CAP 1152242.

- On October 9, 2008 during the Unit 2 core reload, the licensee damaged a control rod in a new fuel assembly. At the time, the fuel assembly was being moved through the transfer canal and was in the process of being lifted to the vertical position. During this movement, the control rod impacted a plug that was sticking out of the transfer canal flange. The top of the control rod was bent 5 to 10 degrees. The plug was installed by a contract organization as part of the refueling activities. However, installation of the plug was not previously identified or evaluated due to the failure to adhere to the procedure change process and a lack of supervisory oversight. This issue was captured in the corrective action program as CAP 1154696. This issue was documented as a finding and NCV in Section 1R20.1 of this report.

- On October 13, 2008, an operator doing outage work operated a Unit 1 reactor coolant pump seal injection isolation valve instead of a Unit 2 reactor coolant pump seal injection isolation valve. While the valve was closed seal injection to a Unit 1 reactor coolant pump was lost, however flow to the seal continued via the reactor coolant system. Although the operator had a procedure in-hand that clearly indicated the valve to be manipulated, the operator failed to appropriately resolve conflicts identified through the use of human performance tools. In addition, the operator failed to adhere to the licensee's procedure implementation process. Had these two processes been implemented correctly, the operator would have likely identified that he was about to open a seal injection valve on the incorrect unit. This issue was captured in the corrective action program as CAP 1155146. This issue was also documented as an NCV in Section 1R20.1 of this report.

- During nuclear instrumentation calibration activities on November 6, 2008, a maintenance individual failed to follow procedures regarding the need to verify that the rod control system was in manual. Instead of requesting and evaluating the condition of the rod control system from operations personnel, the maintenance individual decided that the system remained in manual as it had been previously. This resulted in an unexpected control rod movement and a six percent power reduction. This issue was captured in the corrective action program as CAP 1158394. This issue was also documented as an NCV in Section 1R22.1 of this report.

.4 Selected Issue Follow-up Inspection: Review of Unit 2 Shutdown Safety Program Implementation

a. Inspection Scope

On October 1, 2008, the inspectors completed their preliminary assessment of the licensee's failure to assess and manage the increase in risk that resulted from a proposed maintenance activity before performing maintenance. The inspectors identified a violation of 10 CFR 50.65(a)(4) for the licensee's failure to perform an updated risk evaluation prior to removing a steam generator from service following an emergent failure of an RHR pump.

This review constituted one in-depth Problem Identification and Resolution sample as defined in IP 71152.

b. Observations

On September 22, 2008, Unit 2 was in Mode 5 as part of a refueling outage. Both trains of RHR and one SG were considered operable and available for decay heat removal. At approximately 11:00 a.m., licensee personnel determined that the A train of RHR was inoperable because the RHR heat exchanger outlet valve had failed closed. The B RHR train was placed in service and shutdown cooling was restored. Temperature in the reactor coolant system rose about 29F. The licensee subsequently determined that a nut had loosened allowing a bolt to fall out resulting in the valve positioner feedback arm failing and causing the A RHR heat exchanger valve to go to a position opposite its failed safe position.

Technical Specification 3.4.7 required, in part, that one train of RHR be operable and either one additional train of RHR be operable or that one SG be capable of removing decay heat. At the time of the RHR valve failure, the B train of RHR was available and was started for decay heat removal. In addition, one SG was being drained for outage activities but SG 22 was considered available for decay heat removal.

At approximately 1:02 p.m., licensee personnel determined that the AFW pump discharge valve to SG 22 was closed with power removed (MV-32384). Interviews with the Unit 2 Shift Manager determined that the breaker to valve MV-32384 had been opened as part of preparations for later testing activities and was opened shortly after the failure of A train of RHR by a work group performing surveillance testing. The licensee had performed a risk assessment of the surveillance testing activity but the assessment did not include the emergent failure of the A train of RHR. Loss of SG 22 as a heat removal source and the loss of the A train of RHR placed the licensee in an Orange shutdown risk condition. The licensee recognized that they had entered an unplanned Orange shutdown risk path. Approximately 11 minutes later the Orange path was exited when the breaker to valve MV-32384 was closed and the availability of auxiliary feedwater to SG 22 was restored.

Since the licensee restored the remote operation capability of AFW to SG 22 after its discovery, the finding does not represent an immediate or current safety concern. This issue was entered into the corrective action program as CAP 1151611.

Analysis: The inspectors determined that the licensee failed to update a prior risk assessment due to changing plant conditions. Specifically, the licensee did not perform an updated risk evaluation prior to opening the breaker and removing power to valve MV-32384. This plant configuration degraded the auxiliary feedwater makeup to SG 22.

The inspectors determined that the licensee failed to consider risk-significant structures, systems, and components that were unavailable during maintenance and the issue was within the licensee’s ability to foresee and correct and the condition could have been prevented.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, Appendix E, Section 7, Example f, because the plant was placed in a higher risk category requiring additional risk management actions.

IMC 0609, Appendix K, "Maintenance Risk Assessment and Risk Management Significance Determination Process," refers inspectors to IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," which was used to determine the significance of the finding for Unit 2, which was shutdown during the exposure period. In accordance with Section 3.3 the inspectors used Attachment 1, Checklist 2 and determined that item I.C.2 was not being met. Item I.C.2 required available equipment to support two alternate core cooling paths for at least 24 hours.

The inspectors' review of the findings requiring a phase 2 or 3 analysis determined that the finding represented a degradation of the licensee's ability to establish an alternate core cooling path if decay heat removal could not be re-established.

Section 3.4 of Appendix G addressed if a condition or event represented a loss of control. Conditions that meet a loss of control are listed in Table one. Loss of thermal margin is defined as an inadvertent change in reactor coolant system temperature due to a loss of RHR divided by the change in temperature needed to cause boiling that exceeds 0.2. Utilizing the licensee's computer data the inspectors determined that reactor coolant system temperature increased by 28.7 degrees during the loss of RHR and that an increase of 96.3 degrees would have been required to reach boiling. This resulted in a calculated change of 0.29 which is greater than the minimum 0.2 required.

The RIII senior reactor analyst performed a phase 3 SDP evaluation using the IMC 0609, Appendix G worksheet for loss of RHR in plant operating state POS 1. The licensee provided information that the time to boil given actual conditions was much longer than 2 hours with a full steam generator available for decay heat removal. In solving the SDP worksheet, the senior reactor analyst assumed that the failure of the operating train of RHR resulted in a loss of RHR event, train B RHR was available to put into service, and that the auxiliary feedwater supply to SG 22 was easily recoverable prior to boil-off of the existing inventory in the SG. Given credit for these recovery actions, the senior reactor analyst determined that the finding was of very low safety significance (Green).

Enforcement: Since this violation was licensee identified, the enforcement aspect is described in Section 4OA7 of this report.

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

.1 Unit 2 Manual Reactor Trip

a. Inspection Scope

The inspectors reviewed the licensee's response to a Unit 2 manual reactor trip that occurred on October 30, 2008. Following the reactor trip, the inspectors immediately reported to the control room to monitor the status of the Unit 2 reactor, determine whether any complications had occurred, and to assess the operating crew's response to the reactor trip. These activities were completed by talking with operations personnel, direct observations of the operating crew, reviewing procedures, and conducting walkdowns of the control room panels. The inspectors also observed troubleshooting activities to determine the cause of an equipment failure that occurred prior to the manual reactor trip. Documents reviewed during this inspection are listed in the Attachment. This event is also discussed in Section 4OA3.3 of this report.

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

b. Findings

No findings of significance were identified.

.2 (Open) LER 05000306/2008-001: Unanalyzed Condition Due to Both Trains of Component Cooling Being Susceptible to a Postulated High Energy Line Break

This event, which was discovered on July 31, 2008, is discussed in Section 1R15 of this inspection report. The inspectors documented the issue discussed in the LER as a URI pending the review of additional information from the licensee.

This event follow-up review was not counted as an inspection sample because the inspection was not complete.

.3 (Closed) LER 05000306/2008-002: Unit 2 Manual Reactor Trip During Low Power Physics Testing

On October 30, 2008, operations personnel manually tripped the Unit 2 reactor after experiencing a random rod control fuse failure. Prior to the fuse failure, operations personnel were moving Control Bank A control rods as part of start-up physics testing. During the control rod movement, operations personnel received a control rod urgent failure alarm. Immediately following the alarm, the operators noticed that the Bank A, Group 1 control rods stopped moving while the Bank A, Group 2 control rods continued to move. Operations personnel stopped the Group 2 control rods from moving by placing the rod control system in manual. Because the inability to move rods occurred with physics testing in progress, and rods were not aligned as required, a reactor trip was inserted by licensed operators. Subsequent troubleshooting determined that a fuse in a moveable gripper bus duct disconnect switch had failed. The licensee was unable to determine the cause of the failure. Corrective actions for this issue included replacing all moveable gripper bus duct disconnect fuses. The inspectors reviewed the licensee's response to this event and were unable to identify a performance deficiency. As a result, no findings were documented. No NRC enforcement issues were identified. Documents reviewed as part of this inspection are listed in the Attachment. This LER is closed.

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

.4 Review of Safe Shutdown Impacts Due to Operator's Respirator Qualification Expiring

a. Inspection Scope

The inspectors interviewed operations, engineering and nuclear oversight personnel and reviewed records to determine the facts surrounding CAP 1155361, "Operator On-Shift Qualification Deficiencies."

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

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix R, Section J due to the licensee's failure to ensure that an alternate safe shutdown access path was provided with emergency lighting units that contained at least an 8-hour battery power supply.

Description: In May 2008, a non-licensed operator's respirator qualification expired. The qualification was not renewed due to an ongoing medical condition. Operations management reviewed several procedures and discussed the issue with operations training personnel. Following this review and discussion, operations management determined that the non-licensed operator could continue to perform the auxiliary building plant equipment operator duties without being respirator qualified.

In October 2008, nuclear oversight personnel identified that the non-licensed operator may not be able to meet the requirements of Procedure F5, Appendix B, "Control Room Evacuation (Fire)." Specifically, Prairie Island Nuclear Generating Plant Calculation GEN-PI-055, "Safe Shutdown Timeline for Areas 13 and 18," assumed that the actions taken by the auxiliary building plant equipment operator following this type of fire started in the control room. Due to the design of the carbon dioxide fire suppression system at Prairie Island, it was highly likely that the non-licensed operator would have needed to wear a respirator to travel from the control room to the auxiliary building using the credited safe shutdown access path.

The inspectors discussed this issue with operations management. In addition, the inspectors questioned operations management and reviewed additional documentation to determine whether the licensee would be able to complete their safe shutdown actions within the times assumed in the safe shutdown analysis. Operations management told the inspectors that one of the following options would have been used to ensure that the plant was safety shut down following a control room fire:

- The non-licensed operator would perform the shift technical advisor's actions (and vice versa) or

- The non-licensed operator would use an alternate travel path to get to the auxiliary building.

The inspectors had several concerns with the licensee's options. First, the licensee had not identified nor evaluated these options prior to allowing the operator to remain on-shift. Second, the actions performed by the shift technical advisor may require respirator use for the same reason discussed above. And third, the non-licensed operator's use of an alternate travel path following a control room fire failed to comply with 10 CFR 50, Appendix R due to the lack of emergency lighting for the alternate path. Because problems existed with the licensee's evaluation and corrective actions, the NRC's further inspection added significant value. The finding has been classified as NRC identified, because the NRC added value as defined in IMC 0612.

Analysis: The inspectors determined that the licensee's failure to ensure that the proposed alternate safe shutdown pathway was provided with emergency lighting units with at least an 8-hour battery power supply was a performance deficiency that required an evaluation using the Significance Determination Process. The inspectors determined that this issue was more than minor because if left uncorrected, the failure to properly evaluate alternative actions against regulatory requirements could become a more significant safety concern. The finding affected the mitigating systems cornerstone. The inspectors determined the significance of this finding using IMC 0609, Appendix F, "Fire Protection Significance Determination Process." The inspectors assigned a post-fire safe shutdown finding category to this issue using Table 1.1.1 of IMC 0609, Appendix F. In addition, the inspectors assigned a low degradation rating to this issue. Using the guidance provided in Step 1.3 of IMC 0609, Appendix F, the inspectors concluded that this issue was of very low safety significance (Green). The inspectors also determined that this finding was cross-cutting in the Human Performance, Decision Making area because the licensee failed to make this safety-significant/risk-significant decision using a systematic process that included a review of the safe shutdown analysis timeline and input from fire protection personnel (H.1(a)).

Enforcement: Section J to 10 CFR Part 50, Appendix R, requires all areas needed for operation of safe shutdown equipment and access and egress thereto be provided with emergency lighting units with at least an 8-hour battery power supply. Contrary to the above, on May 24, 2008, the licensee allowed a non-licensed operator to remain on-shift and potentially perform safe shutdown activities using a travel pathway that failed to have emergency lighting units that contained at least an 8-hour battery power supply. However, because this violation is of very low safety significance and was entered into your corrective action program as CAP 1155361, it was treated as an NCV consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000282/2008005-07; 05000306/2008005-07)**. Corrective actions for this issue included removing the non-licensed operator from shift duties (which removed the need to use the alternate travel path), revising procedures to ensure that the safe shutdown analysis timeline was reviewed when making fire protection related decisions, and providing additional administrative controls to ensure that non-respirator qualified operations personnel were not allowed to perform on-shift duties.

4OA5 Other Activities

.1 (Closed) Temporary Instruction (TI) 2515/176, "Emergency Diesel Generator Technical Specification Surveillance Requirements Regarding Endurance and Margin Testing"

a. Inspection Scope

The objective of TI 2515/176 was to gather information to assess the adequacy of nuclear power plant emergency diesel generator endurance and margin testing as prescribed in plant-specific TS. The inspectors reviewed the licensee's TS, procedures, and calculations and interviewed licensee personnel to complete the TI. The information gathered for this TI was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation on December 17, 2008. This TI is complete at Prairie Island Nuclear Generating Plant; however, this TI 2515/176 will not expire until August 31, 2009. Additional information may be required after review by the Office of Nuclear Reactor Regulation.

b. Findings

No findings of significance were identified.

.2 (Closed) TI 2515/172, Reactor Coolant System Dissimilar Metal Butt Welds

a. Inspection Scope

The inspectors conducted a review of the licensee's dissimilar metal butt weld (DMBW) mitigation and inspection program to determine if it was implemented in accordance with the industry self-imposed mandatory requirements of Materials Reliability Program (MRP)-139, "Primary System Piping Butt Weld Inspection and Evaluation Guidelines." This review was conducted in accordance with TI 2515/172, "Reactor Coolant System Dissimilar Metal Butt Welds" for both Units 1 and 2.

The documents reviewed by the inspector for this inspection are listed in the Attachment to this report.

From September 24, 2008, through October 3, 2008, the inspectors performed a review in accordance with TI-172, which included the following:

(1) Licensee's Implementation of the MRP-139 Baseline Inspections

The inspectors observed activities pertaining to this section during the last outage (1R25). The results of this review were documented in NRC Integrated IR 05000282/2008002; 05000306/2008002.

(2) Volumetric Examinations

The inspectors observed and/or reviewed records for the following volumetric examinations.

a. The inspectors observed activities pertaining to this section (unmitigated weld examination) during the last outage (1R25). The results were documented in NRC Integrated IR 05000282/2008002; 05000306/2008002.

b. Unit 1 did not have any welds pertinent to MRP-139, so inspection of volumetric examinations for such welds was not applicable. For Unit 2, the inspectors performed a records review from the current outage of the UT data for the weld overlay repair of the pressurizer surge nozzle DMBW (W-17) and the adjacent stainless steel safe-end to pipe/fitting weld. The inspectors performed the reviews of volumetric examination identified above to determine if:

- the examinations were performed in accordance with the guidelines in MRP-139, Section 5.1;
- the examinations were performed consistent with the NRC staff relief request authorization for the weld overlay;
- the examination coverage warranted further evaluation, and if so, the inspector reviewed the licensee's basis for achieving the inspection coverage credited;
- the volumetric examinations were performed by qualified personnel; and
- deficiencies were appropriately dispositioned.

(3) Weld Overlays

For Unit 1, it was previously verified during outage 1R25 to contain no susceptible welds as described in MRP-139 (i.e., no Alloy 600/82/182 butt welds).

For Unit 2, the inspectors observed the weld overlay repairs completed for the pressurizer surge nozzle (Weld W-17). The inspectors performed the review of weld overlays identified above to determine if:

- the overlays were performed in accordance with ASME Code requirements as modified by the NRC staff relief request authorizations;
- the licensee submitted appropriate relief requests and obtained Office of Nuclear Reactor Regulation staff authorization to install the weld overlays;
- the overlay welding was performed by qualified personnel; and
- deficiencies were appropriately dispositioned and resolved.

(4) Mechanical Stress Improvement

There were no stress improvements performed or planned by the licensee. Therefore, the inspectors did not perform a review for this inspection attributed.

(5) Inservice Inspection Program

The inspectors observed activities pertaining to this section during the last outage (1R25). The results were documented in NRC Integrated IR 05000282/2008002; 05000306/2008002.

b. Observations

Summary: Prairie Island Unit 1 is a Westinghouse two loop designed plant and was previously verified during refueling outage 1R25 to contain no susceptible welds as described in MRP-139 (i.e., no Alloy 600/82/182 butt welds).

Prairie Island Unit 2 is also a Westinghouse two loop designed plant and was verified during outage 1R25 to contain only one susceptible weld (pressurizer surge line nozzle weld). This weld received a Performance Demonstration Initiative qualified ultrasonic baseline examination of approximately 94 percent of the required volume in November 2006 and another pre-weld overlay volumetric examination in 2008 during refueling outage 2R25. The licensee mitigated this weld with a full SWOL employing a machine GTAW temper bead weld process during 2R25. The licensee has complied with the MRP-139 categorization of welds and baseline inspection requirements. No deviations from MRP-139 requirements have been taken or are planned for Unit 1 or Unit 2. This TI is now considered complete for both Units 1 and 2 since the former contains no susceptible welds that have been identified and the single susceptible weld for the latter has been mitigate with a SWOL.

In accordance with requirements of TI 2515/172, Revision 0, the inspectors evaluated and answered the following questions:

(1) Licensee's Implementation of the MRP-139 Baseline Inspections

1. Have the baseline inspections been performed or are they scheduled to be performed in accordance with MRP-139 guidance?

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

2. Is the licensee planning to take any deviations from the MRP-139 baseline inspection requirements? If so, what deviations are planned, what is the general basis for the deviation, and was the NEI 03-08 process for filing a deviation followed?

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

(2) Volumetric Examinations

1. Performed in accordance with the examination guidelines in MRP-139, Section 5.1, for unmitigated welds or mechanical stress improvement welds and consistent with NRC staff relief request authorization for weld overlaid welds?

   The inspectors observed activities pertaining to this section (unmitigated weld examinations) during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

2. Performed by qualified personnel? (Briefly describe the personnel training/ qualification process used by the licensee for this activity.)

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

3. Performed such that deficiencies were identified, dispositioned, and resolved?

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

(3) Weld Overlays

1. Performed in accordance with ASME Code welding requirements and consistent with NRC staff relief request authorizations? Has the licensee submitted a relief request and obtained Office of Nuclear Reactor Regulation staff authorization to install the weld overlays?

   Yes. The weld overlay for the Unit 2 pressurizer surge nozzle was performed in accordance with ASME Code welding requirements and consistent with the approved NRC relief request.

Yes. The licensee submitted a relief request and obtained Office of Nuclear Reactor Regulation staff authorization to install the weld overlay.

2. Performed by qualified personnel? (Briefly describe the personnel training/ qualification process used by the licensee for this activity.)

   Yes. For the weld overlay reviewed by the inspectors for Unit 2, the welders fabricating the overlay had performed an ASME Code, Section IX, "Welder Performance Qualification," in accordance with the vendor's program for the weld overlay activities performed. The welder qualification records were transmitted to the licensee for review and concurrence in support of the 2R25 weld overlay work. The inspectors reviewed the welder qualification records.

3. Performed such that deficiencies were identified, dispositioned, and resolved?

   Yes. For Unit 1, it was previously identified during outage 1R25 that the Unit contained no susceptible welds as described in MRP-139 (i.e., no Alloy 600/82/182 butt welds).

   Yes. For Unit 2, the licensee's vendor first failed to correctly document the weld travel speed calling into question whether the correct heat input had been maintained, then subsequently failed to establish the correct parameters while applying a temper bead weld during weld overlay fabrication. While the former required a document review, which resulted in an acceptable condition, the latter required the vendor to grind out affected weld metal and re-weld that portion of the overlay repair. The inspectors concluded that the licensee had taken appropriate corrective actions to resolve these deficiencies. The inspectors reviewed the final Dye Penetrant and UT records for the weld overlay, which revealed no recordable indications.

(4) <u>Mechanical Stress Improvement</u>

No stress improvement activities have been performed for DMBWs nor did the licensee plan to perform mechanical stress improvement as a mitigation strategy for DMBWs.

(5) <u>Inservice Inspection Program</u>

1. Has the licensee prepared an MRP-139 ISI program? If not, briefly summarize the licensee's basis for not having a documented program and when the licensee plans to complete preparation of the program.

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

2. In the MRP-139 ISI program, are the welds appropriately categorized in accordance with MRP-139? If any welds are not appropriately categorized, briefly explain the discrepancies.

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

3. In the MRP-139 ISI program, are the ISI frequencies, which may differ between the first and second intervals after the MRP-139 baseline inspection, consistent with the ISIs frequencies called for by MRP-139?

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

4. If any welds are categorized as H or I, briefly explain the licensee's basis of the categorization and the licensee's plans for addressing potential primary water stress corrosion cracking.

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

5. If the licensee is planning to take deviations from the ISI "requirements" of MRP-139, what are the deviations and what are the general bases for the deviations? Was the NEI 03-08 process for filing deviations followed?

   The inspectors observed activities pertaining to this section during the last outage (1R25). The results were detailed in NRC Integrated IR 05000282/2008002; 05000306/2008002.

c. Findings

No findings of significance were identified.

.3 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 8, 2009, the inspectors presented the inspection results to M. Wadley, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The preliminary results of the licensee's failure to assess and manage the increase in risk that may result from the proposed maintenance activities before performing maintenance with Mr. S. Northard, Plant Manager, on October 1, 2008;

- The results of the Inservice IP 71111.08 and TI 172 with Mr. M. Wadley, Site Vice President, on October 3, 2008;

- A telephone exit for TI 2515/176 was conducted with Ms. Sonja Myers, Design Engineering Manager, and other licensee staff on December 4, 2008;

- The licensed operator requalification training biennial written examination and annual operating test results with Mr. T. Ouret, Supervisor, Initial License Training, on December 22, 2008; and

- The annual review of Emergency Action Level and Emergency Plan changes with Mr. J. Callahan, Emergency Preparedness Manager, via telephone on December 23, 2008.

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

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements, which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

Cornerstone: Mitigating Systems

10 CFR 50.65(a)(4) requires in part, that the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities before performing maintenance. Contrary to the above, on September 22, 2008, licensee personnel failed to adequately manage the risk associated with the initiation of planned testing activities after emergent equipment failures. Specifically, at approximately 11:00 a.m., on September 22, 2008, Unit 2 Train A RHR failed and shortly thereafter, the breaker to the valve isolating auxiliary feedwater to SG 22 was opened resulting in an unplanned Orange path entry. This condition existed for approximately two hours and 13 minutes before licensee personnel recognized the condition and restored power to the AFW isolation valve. The licensee entered this issue into their corrective action program as CAP 1162470.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Wadley, Site Vice President
J. Sorensen, Director Site Operations
S. Northard, Plant Manager
T. Allen, Business Support Manager
J. Anderson, Regulatory Affairs Manager
L. Clewett, Operations Manager
B. Flynn, Safety and Human Performance Manager
R. Hite, Radiation Protection and Chemistry Manager
R. Madjerich, Production Planning Manager
J. Muth, Nuclear Oversight Manager
M. Schimmel, Site Engineering Director
M. Schmidt, Maintenance Manager
J. Sternisha, Training Manager

Nuclear Regulatory Commission

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

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000306/2008005-01	NCV	Failure of Contractors to Follow Welding Procedures (Section 1R8.1)
05000306/2008005-02	URI	Component Cooling Water Susceptible to High Energy Line Break Interaction (Section 1R15.1)
05000306/2008005-03	NCV	Control Rod Bent due to Contractors' Failure to Follow Procedures (Section 1R20.1b(1))
05000282/2008005-04; 05000306/2008005-04	NCV	Operator Manipulates Incorrect Component due to Failure to Follow Procedures (Section 1R20.1b(2))
05000306/2008005-05	NCV	Decrease in Reactor Power due to Failure to Follow Procedures (Section 1R22.1b(1))
05000282/2008005-06; 05000306/2008005-06	URI	Abnormal Operating Procedure Entry Conditions (Section 1R22.1b(2))
05000282/2008005-07; 05000306/2008005-07	NCV	Respirator Qualification Deficiency Results in Non-Compliance with 10 CFR Part 50, Appendix R (Section 4OA3.4)

Closed

05000306/2008005-01	NCV	Failure of Contractors to Follow Welding Procedures (Section 1R8.1)
05000306/2008005-03	NCV	Control Rod Bent due to Contractors' Failure to Follow Procedures (Section 1R20.1b(1))
05000282/2008005-04; 05000306/2008005-04	NCV	Operator Manipulates Incorrect Component due to Failure to Follow Procedures (Section 1R20.1b(2))
05000306/2008005-05	NCV	Decrease in Reactor Power due to Failure to Follow Procedures (Section 1R22.1b(1))
05000282/2008005-07; 05000306/2008005-07	NCV	Respirator Qualification Deficiency Results in Non-Compliance with 10 CFR Part 50, Appendix R (Section 4OA3.4)
05000306/2008-002	LER	Unit 2 Manual Reactor Trip During Low Power Physics Testing

Discussed

05000306/2008-001	LER	Unanalyzed Condition Due to Both Trains of Component Cooling Being Susceptible to a Postulated High Energy Line Break

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

- TP 1637; Winter Plant Operation; Revision 39

1R04 Equipment Alignment

- C37.11; Chilled Water Safeguard System Operation; Revision 21
- C37.11-1; Chilled Water Safeguards System; Revision 18
- CAP 1156504; 122 Control Room Chiller Would Not Start After Cooling Water Pipe Replacement; October 22, 2008
- Control Room LCO Logs for 11/17-24/2008
- C1.1.35-3; Cooling Water System; Revision 28
- 2C14; Component Cooling System – Unit 2; Revision 27

1R05 Fire Protection

- Safe Shutdown Analysis
- Procedure F5, Appendix A; Fire Plan Maps; Various Revisions

1R08 Inservice Inspection Activities

- CAP 1152793; Weld Overlay QC and Step Sequencing; dated September 29, 2008
- CAP 1129454; Inadequate Thread Engagement; dated March 1, 2008
- CAP 1129494; SG Tubing Degradation Observed; dated March 2, 2008
- CAP 1127993; Misaligned Hanger Found; dated March 20, 2008
- CAP 127340; Clamp and Hanger not Centered Above Pipe; dated December 7, 2006
- CAP 1127833; Slight Bend in Rod; dated February 13, 2008
- CAP 1127353; Slight Bend in flange of I-Beam Near Welded Base; dated February 14, 2008
- CAP 1131428; Six Minor packing and Filling Drips Dispositioned by Work Request; dated March 17, 2008
- CAP 1134694; Reactor Coolant System Integrity Test; dated March 16, 2008
- CAP 1127833; Clamp and Hanger Not Centered Above Pipe; dated December 7, 2006
- CAP 1153576; AREVA CR Identified Two Issues with the Pressurizer Weld Overlay Project; dated October 3, 2008
- Visual Examination of IWE Interfaces (VT-1)
- 2008 V069; Bolted Connection, ILRT Pressure Sensing Line, B5; dated February 29, 2008
- PQR PQ5394-002 PQR for WPS WP1/8/43/F43OLTBSCa3; dated June 18, 2007
- PQR PQ7200-004 PQR for WPS WP1/8/43/F43OLTBSCa3; dated August 17, 2007
- PQR PQ7213-001 PQR for WPS WP1/8/43/F43OLTBSCa3; dated August 8, 2007
- PQR PQ7214-001 PQR for WPS WP1/8/43/F43OLTBSCa3; dated July 12, 2007
- WPS 55-WP8/8/F6AWW3-07; Machine GTAW for SWOL 309L SS; dated February 14, 2007
- PQR PQ7062-004 PQR for WPS 55-WP8/8/F6AWW3-07; dated January 3, 2006
- WO 306550; Boric Acid Filter to RMW Line Emerg BO; dated November 28, 2006

- 50-9036744; Process Traveler for Prairie Island Unit 2 Pressurizer Surge Nozzle Weld Overlay; dated October 1, 2008
- 55-O10069; Attachment 1 Structural Weld Overlay Weld Control Records; dated September 25-30, 2008
- Relief Request 2-RR-4-8 Proposed Alternatives for Application of Structural Weld Overlay to the Prairie Island Nuclear Generating Plant Unit 2 Pressurizer Surge Nozzle Weld; dated June 25, 2007
- 55-O10069-000; Operating Instructions O10069 Prairie Island PZR Machine GTAW Structural Weld Overlay; dated September 12, 2008
- Drawing 8017249D Prairie Island Unit 2 Pressurizer Surge Nozzle Overlay Design; Revision 1
- Drawing 8017255D Prairie Island Unit 2 Pressurizer Surge Nozzle Overlay Implementation
- 1-PRZ-25; Revision 2
- Drawing 8017247C Prairie Island Unit 2 Pressurizer Surge Nozzle Design; Revision 1
- Welder Performance Qualification Records Qualification records for Welders to Perform Remote GTAW Weld Overlays; dated September 12, 2008
- 2008P004; Int. Attachment (Double Spring) H-1/IA; dated September 26, 2008
- UT Calibration Sheet 2008U021; Pipe-to-Elbow Weld W-6; dated September 25, 2008
- UT Calibration Sheet 2008U022; Elbow-to-Pipe Weld W-7; dated September 25, 2008
- UT Calibration Sheet 2008U025; Pipe-to-Elbow Weld W-8; dated September 25, 2008
- UT Calibration Sheet 2008U024; Elbow-to-Pipe Weld W-9; dated September 25, 2008
- W18-NDE-300-00; Weld Overlay Examination Data Sheet: W18-EDS-01; dated October 10, 2008
- UT Calibration Sheet CS02-W18; Weld Overlay of Weld W-18; dated October 8, 2008
- UT Calibration Sheet CS04-W18; Weld Overlay of Weld W-18; dated October 8, 2008
- UT Calibration Sheet CS05-W18; Weld Overlay of Weld W-18; dated October 8, 2008
- UT Calibration Sheet CS06-W18; Weld Overlay of Weld W-18; dated October 8, 2008
- W18-NDE-280-00; Liquid Penetrant Examination of Weld W-18 Overlay; dated October 8, 2008
- SWI NDE-PT-1; Solvent Removable Visible Dye Penetrant Examination; Revision 1
- 54-ISI-829-09; Manual Ultrasonic Examination of Dissimilar Metal Piping Welds; dated February 8, 2008
- 54-ISI-838-09; Manual Ultrasonic Examination of Weld Overlaid Similar and Dissimilar Metal Welds; dated August 20, 2007
- FP-PE-NDE-402; Ultrasonic Examination of Austenitic Pipe Welds - Supplement 2; Revision 1
- FP-PE-NDE-530; Visual Examination, VT-3; Revision 2
- 54-PT-200-08; Color Contrast Solvent Removable Liquid Penetrant Examination of Components; Revision 8
- FP-PE-NDE-520; Visual Examination for Leakage, VT-2; Revision 1
- H2 Boric Acid Corrosion Control Program; Revision 13
- SP 2392; Unit 2 Insulated Bolted Connection Inspection; Revision 4
- D63; Installation Guidelines for Threaded Fasteners (Studs or Bolts); Revision 18
- PINGP 1507; Boric Acid Corrosion Control Leak Inspection; Revision 2
- Report 51-9036873-00; A CMOA Evaluation for Prairie Island Unit 2 at EOC 23; dated January 31, 2007
- Drawing Top of Tube Sheet; Steam Generator Tubesheet Elevations; Revision 2
- 2H25.1; Unit 2 SG Degradation Assessment; Revision 5
- 2H25.2; Unit 2 Steam Generator Condition Monitoring; Revision 5
- 2H25.3; Unit 2 Steam Generator Tube Repair Criteria; Revision 2
- D27.21; Steam Generator Tube Repair; Revision 29
- WPS FP-PE-B31-P8P8-GTSM-037 Groove Welds and Fillet Welds, P8-P8, GTAW/SMAW, Without PWHT; Revision 2

- PQR DAEC W-66 PQR for WPS FP-PE-B31-P8P8-GTSM-037; dated October 12, 1989
- PQR NSP-1270/1271 PQR for WPS FP-PE-B31-P8P8-GTSM-037; Revision 0
- PQR DAEC W-12 PQR for WPS FP-PE-B31-P8P8-GTSM-037; Revision 1
- PQR PAL-SM-8-8(2) PQR for WPS FP-PE-B31-P8P8-GTSM-037; Revision 0
- WPS WP1/8/43/F43OLTBSCa3 Machine GTAW for SWOL – Alloy 82 & 52 August 26, 2008

1R11 Licensed Operator Requalification

- Licensed Operator Examination Results; CY 2008

1R12 Maintenance Effectiveness

- Maintenance Rule Bases Document
- Maintenance Rule Evaluation (MRE) 01122173; 12 CL pump Unavailability Exceeded Schedule; March 5, 2008
- MRE 01123287-01; Steam exclusion Damper CD-34188 Inoperable; Revision 0
- MRE 1123680; D2 EDG LO cooler gasket Leak; Revision 0
- MRE 01123998; 22 DD CL pump Air Receiver A did not meet SP 1105B AC; Revision 0
- MRE 01125249-02; D1 Jacket Coolant Pump Seal is Leaking; Revision 0
- OPR-1151815-1; 121 CL pump Operability Determination; Revision 0
- OPR-1135817-01; 121 CL pump Operability Determination; Revision 0
- EC 13227; Basis for Availability of 121 Motor Driven CL Pump; September 27, 2008
- GAR 1048278 Action 41; Update Cooling Water Success Criteria in MSPI Basis Document; October 29, 2008
- CAP 1122173; 12 CL pump Unavailability Exceeded Schedule; December 26, 2007
- CAP 1123287; CD-34188 Did Not Close Completely during SP 1112; January 9, 2008
- CAP 1123998; 22 DD CL pump Air Receiver A did not meet SP 1105B AC; January 17, 2008
- CAP 1125249; D1 Jacket Coolant Pump Seal is Leaking; January 28, 2008

1R13 Maintenance Risk Assessment and Emergent Work

- CAP 1151738; CV-31240 No Lock Washer Under Standoff Stud Nut; September 23, 2008
- CAP 1151611; Evaluate Unplanned Orange Path on Safety Shutdown Assessment; September 22, 2008
- CAP 1151575; 21 RHR Heat Exchanger Outlet Valve CV-31238 Feedback Arm Disconnected; September 22, 2008
- CAP 1145214; Foreign Material Discovered in 21 RHR Pit; July 27, 2008
- WO 324614; 21 RHR Heat Exchanger CC Inlet MOV Lube
- Operations LCO Logs; September 22, 2008

1R15 Operability Evaluations

- OPR 1152949; Unplanned LCO Entry Due to Bus 15 Sequencer; Revision 0
- CAP 1152949; Unplanned LCO Entry Due to Bus 15 Sequencer; September 30, 2008
- SP 1094; Bus 15 Load Sequencer Test; Revision 24, Including Temporary Change
- WO 369955; SP 1094 Bus 15 Load Sequencer Monthly Test
- WO 351078; SP 1094 Bus 15 Load Sequencer Monthly Test
- 1C20.7 AOP2; Bus 15 Load Sequencer Out of Service; Revision 8
- OPR 1156119; Gaskets for Unit 1 Pressurizer Safety Relief Valves RC-10-1 and RC-10-2; Revision 0
- CAP 1156109; 2RC-10-1 and 2RC10-2 Pressurizer Safety Valves; October 19, 2008

- CAP 1156119; Appears Wrong Gasket Was Installed in RC-10-1 and RC-10-2; October 19, 2008
- Need to document ACE reviews of CAPs 1156109 & 1156119 after ACEs become available
- Drawing H-52137-1; Crosby Valve and Gage, Nozzle Type Safety Relief Valve Style HB-BP-86
- Material Issue Ticket 06712000; Catalog ID KVL1YK, Gasket Spiral Wound
- Master Material Catalog ID Description for ID KVL1YL
- Purchase Order 272177; Item VL1YL / 6RV58LSB, Gasket Flexatalic
- ASME Code Case N-513-2; Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping Section XI, Division 1; dated February 20, 2004
- CAP 1143812; Turbine Building HELB Funding Delays Could Affect Project Success; July 10, 2008
- CAP 1145695; CC Piping Adjacent to HELB Location in Turbine Building; July 29, 2008
- CAP 870304; Update USAR to Incorporate Turbine building HELB Analysis; July 26, 2005
- CAP 1162511; Missed Opportunities to Identify HELB and CC system Interaction; December 15, 2008
- CAP 34876; Turbine building HELB Analysis; April 8, 2002
- CAP 53226; Delay HELB Analysis Corrective Action Due to Budget; August 3, 2001
- CAP 553065; Evaluate Turbine Building HELB Analysis; November 25, 2003
- CAP 31550; Turbine Building HELB Analysis; February 18, 2002
- LER 2-08-01; Unanalyzed Condition Due to Both Trains of Component Cooling Being Susceptible to a Postulated High Energy Line Break; September 29, 2008
- 2C14AOP1; Loss Of Component Cooling; Revision 16
- 2C14; Component Cooling System – Unit 2; Revision 27
- 1C14; Component Cooling System – Unit 1; Revision 26
- C1.1.14-1; Unit 1 Component Cooling System; Revision 24
- C1.1.14-2; Unit 2 Component Cooling System; Revision 29
- CAP 737382; Non-Seismic Equipment in CC System Pressure Boundary; August 2, 2004
- CAP 1002268; HELB Project Cost Overruns; October 28, 2005
- OPR 1145695; CC Piping Adjacent to HELB Location in Turbine Building; August 1, 2008
- CAP 826114; Perform Seismic Analysis of 1-CC-138 Up to CC-71-1 and CC-71-2; March 29, 2005
- NF-39246-1; Unit 2 Component Cooling Water System; Revision 76
- NF-39246-2; Unit 2 Component Cooling Water System; Revision G
- ENG-CS-278; Seismic Qualification of Components in CC System Pressure Boundary; Revision 1
- PI-233-39P23A; Pipe Stress Analysis – CC System, Part 23A; Revision 0
- PI-233-39P23B; Pipe Stress Analysis – CC System, Part 23B; Revision 0
- PI-233-39P23C; Pipe Stress Analysis – CC System, Part 23C; Revision 0
- PI-233-39P23D; Pipe Stress Analysis – CC System, Part 23D; Revision 0
- PI-233-39P23E; Pipe Stress Analysis – CC System, Part 23E; Revision 0
- SL-11973-014; Chemistry Lab Component Cooling Study; Revision 0
- CAP 1163206; Operable but Nonconforming Determination for CAP 737382; December 19, 2008
- CAP 1162939; CAP Actions Not Completed for CAP 737382; December 18, 2008
- DC-496; Design Change to Install 1 Inch Component Cooling Water Piping to the Hydrogen/Oxygen Generator; June 14, 1974
- NF-39297-1; Sampling Systems Units 1 and 2

1R18 Modifications

- CAP 1152779; Incorrect Parts Supplied By Vendor for SI-9 Check Valves; September 29, 2008
- CAP 1150327; Engineering Change Not Ready for 2SI-9 Check Valve Work for 2R25; September 11, 2008
- EC13095; Engineering Change for SI Check Valves SI-9-1 thru SI-9-6 and 2SI-9-1 thru 2SI9-6
- Drawing X-HIAW-1001-80; Velan Engineering Drawing for 6" Primary Nuclear Swing Check Valve; Revision H
- Drawing X-HIAW-1-326; Velan Engineering Drawing for 6" Primary Nuclear Swing Check Valve; Revision 76
- VEL-SFVM-2004; Velan Forged Steel Valves Installation and Operation Manual; No Revision
- EC 7712; Equivalency Evaluation for SI Check Valves SI-9-1 thru SI-9-6 and 2SI-9-1 thru 2SI9-6; Revision 2
- EC 8032; Engineering Change for Velan SI Swing Check Valve Cotter Pin to Machined Pin; Revision 1
- EEC 1546; Equivalent Engineering Change – 6" Velan Swing Check Valve Safety-Related Internal Part Number Changes
- Procedure C35; Cooling Water; Revision 65

1R19 Post-Maintenance Testing

- SP 2092D; Safety Injection Check Valve Test (Head On) Part D: Low Head SI Discharge Flow Path Verification; Revision 9A
- SP 2126; Turbine Building Cooling Water Header Isolation SI Relays 2SI-12X and 2SI-22X Contact Verification Test; Revision 7
- LCO Log Dated October 21, 2008
- CAP 1156419; Train A Cooling Water MV-32031 Tested Outside Reference Range; October 21, 2008
- SP 1194; Cardox (Carbon Dioxide) 18-Month System Test; Revision 18
- WO 366492; Install Upgraded EMPC/19419 Cardox Pilot Control Panel
- Drawing X-HIAW 195-12; Turbine Building Cooling Water Header Valve; Revision RU
- Engineering Change 13017; Cardox Pilot Valve Cabinet Upgrade; Revision 0
- WO 345451; 22 TDAFWP Recirculating Lube Oil Cooling Air Operated Valve Overhaul
- WO 371743; U2 CV-31419 Found Open
- SP 2102; 22 Turbine-driven AFW Pump Monthly Test; Revision 84
- 2M-AF-3132-1-22; Isolation, Restoration and Testing of 22 Aux Feed Pump; Revision 0
- CAP 1157248; 22 AFW Pump Recirc CV-31419 Found Open/Solenoid De-energized; October 29, 2008
- Engineering Change 13017; Cardox Pilot Valve Cabinet Upgrade; Revision 0

1R20 Refueling and Outage

- 2C1.2; Unit 2 Startup Procedure; Revision 43
- 2C1.4; Unit 2 Power Operation; Revision 41
- C1-B; Unit Startup Checklist; Revision 20
- C.1.1-B1; Master System Checklist; Revision 3
- C.1.1.5-2; Rod Control and Position Indication System – Unit 2; Revision 10
- C.1.1.7-2; Unit 2 Reactor Control; Revision 14
- C1.1.9-2A; Nuclear Instrumentation System; Revision 2
- C.1.1.15-2; Unit 2 Residual Heat Removal; Revision 28

- C1.2B; Chemistry Mode 3, Hot Standby; Revision 8
- C1-M3; Surveillance Requirements Mode 3, Hot Standby; Revision 12
- D30; Post Refueling Startup Testing; Revision 46
- D58; Heavy Loads Program; Revision 33
- D58.2.9; Unit 2 Reactor Vessel Head Removal; Revision 15
- D58.2.10; Unit 2 Reactor Vessel Head Replacement; Revision 13
- SP 2177; Core Inventory Verification; Revision 14
- SP 2750; Post Outage Containment Close-out Inspection; Revision 31
- SP 2834; Unit 2 Containment Coatings Inspections; Revision 3
- WO 00290047-01; SP 2177 Refuel Core Inventory Verification
- Unit 2 Cycle 25 Core Inventory Verification Video; 10/13/2008
- 50.59 Evaluation 1061 (Document 03FH02-225); Unit 2 Cycle 25 Core Reload; Revision 0
- Westinghouse Reload Safety Evaluation – Prairie Island Unit 2 Cycle 25
- Prairie Island Nuclear Generating Plant Core Operating Limits Report – Unit 2 Cycle 25; Revision 0
- Reactor Startup Following 2R25 Plant Operations Review Committee Meeting 3029 Agenda; October 28, 2008
- Root Cause Report for Bent Control Rod Issue
- Department Clock Reset Yellow Sheet for Mispositioning of Unit 1 Seal Injection Valve
- Human Performance Investigation Results for CAP 1155146
- Operating Experience Smart Sample: FY2007-03; Crane and Heavy Lift Inspection, Supplemental Guidance for IP 71111.20; Revision 1
- NMC Calculation 2005-05621; Analysis of Postulated Reactor Head Load Drop Onto the Reactor Vessel Flange; Revision 3
- NRC Regulatory Issue Summary 2005-25; Clarification of NRC Guidelines for Control of Heavy Loads; Supplement 1
- ASME B30.2-2005; Overhead and Gantry Cranes

<u>1R22 Surveillance Testing</u>

- SP 2070; Reactor Coolant System Integrity Test; Revision 37
- Drawing X-HIAW-1001-6; Flow Diagram Safety Injection System; Revision 76
- Drawing X-HIAW-1001-3; Flow Diagram – Unit 2 Reactor Coolant System; Revision 78
- Setpoint Change Request for 1TM-405R, 1TM-406R, 1TM-407R and 1TM-408R; dated October 24, 2008
- SP 2095; Bus 26 Load Sequencer Test; Revision 23
- WO 352922; SP 2095 Bus 26 Load Sequencer Test
- SP 1090B; 12 Containment Spray Pump Quarterly Test; Revision 14
- WO 353332; SP 1090B 12 Containment Spray Pump Quarterly Test
- CAP 1159063; SI-20-13 Line Appears to Have A Stress Crack; November 13, 2008
- CAP 1159065; Loose Conduit Fitting At U1 Containment Spray Room West Wall Penetration; November 13, 2008
- CAP 1159068; Light Fixture Hanging By Electrical Cord; November 13, 2008
- Control Room Operating Logs; dated November 6, 2008
- 1C5 AOP 2; Uncontrolled Insertion of a Control Rod; Revision 7
- Cycle 08 Biennial Training Plan Revision 3; dated July 23, 2008
- Simulator Exercise Guide P9160S-002 Attachment Evaluation 8; T-Hot Failure, Reactor Coolant System Leak, Loss of Coolant Accident, Loss of Offsite Power; Revision 12
- Simulator Exercise Guide P9160S-001 Attachment 06-23; Rod Insertion/Steam Generator Fault Practice; Revision 0
- Powerpoint Presentation on Rod Control System P9106L-0402; Revision 0

- Initial Licensed Operator Training Lesson Plan P8197L-010; Emergency Operating Procedure Introduction/Procedure Review; Revision 4
- Initial Licensed Operator Training Lesson Plan P8140L-201; Introduction to Simulator Operation; Revision 1
- Initial Licensed Operator Training Lesson Plan P8140L-227; Load Increase, First Stage Pressure Instrument Failure, Leakage into the Component Cooling Water System, Loss of Component Cooling Water System, Reactor Trip, Natural Circulation; Revision 0
- Site Clock Reset Red Sheet; dated November 8, 2008
- Prairie Island Unit 2 Control Room/Reactivity Oversight Plan; dated November 6, 2008
- Safety Evaluation Screening 3081; Delta T Gain Adjustments; Revision 0

4OA1 Performance Indicator Verification

- Mitigating Systems Performance Index Derivation Reports for the Residual Heat Removal System; Fourth Quarter 2007 through Third Quarter 2008
- Mitigating Systems Performance Index Derivation Reports for the Cooling Water System; Fourth Quarter 2007 through Third Quarter 2008

4OA2 Identification and Resolution of Problems

- Unit 2 Shutdown Safety Assessments; September 19 through October 30, 2008
- Figure C1-32; Boiling Curve; Revision 4
- Crew Meeting Review of Noteworthy Event/Near Miss/Change; dated October 2, 2008
- FP-OP-COO-01; Conduct of Operations; Revision 4
- 5AWI 15.6.1; Shutdown Safety Assessment; Revision 12
- Key Card Usage Report for Unit 1 AFW Pump Room Door
- CAP 1156968; Level A CAP Action Complete Without Work Completed; dated October 27, 2008
- CAP 1152949; Unplanned LCO Entry due to Bus 15 Sequencer Inoperable; dated September 30, 2008
- CAP 1121937; Failure to Meet Surveillance Requirement 3.3.4.3 Makes Bus 15 Sequencer Inoperable; dated December 21, 2007
- CAP 1140224; Load Sequencer Test Procedures Inconsistent with Vendor Manual; dated June 4, 2008
- CAP 1153464; Operations Log Keeping Not Meeting Expectations; October 2, 2008
- CAP 1153576; Documentation of AREVA Condition Report 2008-5336; October 3, 2008
- CAP 1156574; 21 Component Cooling Heat Exchanger Foreign Material Exclusion Zone Clarity Issues; October 22, 2008
- CAP 1156659; AREVA Condition Report on Weld Overlay Procedures; October 23, 2008
- CAP 1157124; Spool Piece Left on Roof of TSC Could Interfere with TSC Ventilation Operations; October 28, 2008
- CAP 1158289; TDAFWP Speed Setting Steps in Monthly Surveillance Procedures; November 5, 2008
- CAP 1158388; SV-37015 Has an Air Leak; November 6, 2008
- CAP 1158505; 2C5 AOP2 Not Entered During Reactivity Event; November 7, 2008
- CAP 1159133; Benchmark Industry Standard for Abnormal Procedure Entry; November 14, 2008
- CAP 1159257; HKB #'s Not Discussed in Engineering Manual Section 3.2.1.8; November 14, 2008
- CAP 1159442; MOVs Installed Through Modification 94L473 Have Incorrect Parameters; November 17, 2008

- CAP 1159451; Potential Method Change Without Being Addressed in 50.59; November 17, 2008
- CAP 1159902; Problems Found with the Performance of Screening 2887; November 20, 2008
- CAP 1159911; RPIP 3006 Oxygen Limits Not Equivalent to EPRI Limits; November 20, 2008
- CAP 1159920; Chemistry Procedural Guidance for 10CFR Part 61 Initiation; November 20, 2008
- CAP 1159965; Clarify Section 5.3 Of Revision 4 to Calculation ENG-EE-045; November 20, 2008
- CAP 1159988; Frequency Effects on EDG Loading Unaccounted for in Calculation Revision; November 20, 2008
- CAP 1160011; Radiation Survey Not Complete; November 21, 2008
- CAP 1160012; Information Removed from the USAR Inappropriately; November 21, 2208
- CAP 1160060; NRC Observation from Radiation Shipping Inspection – D11 Procedure; November 21, 2008
- CAP 1160064; Calculation ENG-EE-018 Notation Mistake; November 21, 2008
- CAP 1160067; NRC Observation from Radiation Shipping Inspection – Barrel Yard; ; November 21, 2008
- CAP 1160295; Screening 2887 Missed Items Required to Be Screened; November 24, 2008
- CAP 1160372; Refueling Cavity Leakage Corrective Actions and the Locked Radiation Area; November 24, 2008
- CAP 1160590; Condensate Storage Tank Temperature Configuration Control; November 26, 2008
- CAP 1160610; Typo in OPR 1159988-01 for D5 Frequency Adjust Total; November 26, 2008
- CAP 1160611; Record of 12/79 D2 Diesel Generator Run Per SP 1093 Not Found; November 26, 2008
- CAP 1160903; Change Label Of Critical Characteristic for EC 12146; December 1, 2008
- CAP 1160910; Revise Attachment 1 from Vendor for EC 12146; December 1, 2008
- CAP 1161330; EC 12146 Inadequate Seismic Qualification; December 4, 2008
- CAP 1161364; EC 12191 Blast Analysis Question; December 4, 2008
- CAP 1161368; H2 Storage Analysis Incomplete; December 4, 2008
- CAP 1161373; EC 12191 Adverse Affect to Safety-Related Cooling Water Piping; December 4, 2008
- CAP 1161382; EC 12191 NRC Response Question 159 for CW System; December 4, 2008
- CAP 1161385; Calculation PI-M-024 Referenced Incorrect Construction Code; December 4, 2008
- CAP 1162013; LER 1-07-04 Requires Supplement; December 10, 2008
- CAP 1162343; ALARA Planning Not Performed for 2R25 Fuel Sipping; December 12, 2008
- CAP 1162470; NRC Violation for Unplanned Orange Path in 2R25; December 15, 2008
- CAP 1162511; Missed Opportunities to Identify HELB and CC System Interaction; December 15, 2008
- CAP 1163206; OBN for CAO 737382; December 19, 2008
- NRC Integrated IR 05000282/2008004; 05000306/2008004; dated November 7, 2008

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

- B5; Rod Control System; Revision 5
- Alarm Response Procedure C47013; Location 0106; Rod Control System Urgent Failure; Revision 38
- WCAP-15360; Westinghouse Rod Control System Corrective Maintenance Guide; Revision 1
- Drawing FC-04; Troubleshooting Power Cabinet Phase Failures
- Work Order 371803; Rod Control System Urgent Failure; dated October 30, 2008

- Apparent Cause Report 1157503; Determine Cause of Urgent Failure Alarm During Low Power Physics Testing; dated December 12, 2008
- Westinghouse Technical Bulletin TB-05-3; Potential Concern About the Westinghouse Recommended 25 Ampere Fuse for the Rod Control System Gripper Circuit; dated April 28, 2005
- Westinghouse Technical Bulletin TB-04-3; Cracked Ferrules on Ferraz-Shawmut Fuses; dated January 1, 2004
- Reactor Trip Report; dated October 30, 2008

<u>4OA5 Other Activities</u>

- SP-1334; D1 Diesel Generator 18-Month 24-Hour Load Test; Revision 7
- SP-1335; D2 Diesel Generator 18-Month 24-Hour Load Test; Revision 8
- SP-2334; D5 Diesel Generator 18-Month 24-Hour Load Test; Revision 10
- SP-2335; D6 Diesel Generator 18-Month 24-Hour Load Test; Revision 12
- NMC Calculation (Doc) No. ENG-EE-021; Diesel Generator Steady State Loading for an SI Event Concurrent with Loss of Offsite Power for D1, D2, D5, D6; Revision 3

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program document
CCW	Component Cooling Water
CFR	Code of Federal Regulations
DMBW	Dissimilar Metal Butt Weld
ET	Eddy Current
GTAW	Gas Tungsten Arc Welding
I&C	Instrumentation and Controls
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
MRE	Maintenance Rule Evaluation
MRP	Materials Reliability Program
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OI	Operating Instruction
PI	Performance Indicator
RHR	Residual Heat Removal
SDP	Significance Determination Process
SG	Steam Generator
SI	Safety Injection
SP	Surveillance Procedure
SWOL	Structural Weld Overlay
TI	Temporary Instruction
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
UT	Ultrasonic Examination
WCR	Weld Control Records
WO	Work Order
WPS	Welding Procedure Specifications