November 1, 2005

Mr. T. Palmisano
Site Vice-President
Prairie Island Nuclear Generating Plant
Nuclear Management Company, LLC
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2005008;
05000306/2005008

Dear Mr. Palmisano:

On September 30, 2005, 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 September 29, 2005, with members of your staff.

This 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, the inspectors identified three NRC-identified findings of very low safety significance (Green), all of which involved violations of NRC requirements. Because these three violations were of very low safety significance and because the issues were entered into the licensee's corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. If you contest the subject or severity of a Non-Cited Violation, 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, D.C. 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, D.C. 20555-0001; and the Resident Inspector Office at the Prairie Island Nuclear Generating Plant.

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Sincerely,

/RA/

Richard A. Skokowski, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-282; 50-306
License Nos. DPR-42; DPR-60

Enclosure: Inspection Report 05000282/2005008; 05000306/2005008
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	05000282/2005008; 05000306/2005008
Licensee:	Nuclear Management Company, LLC
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	July 1 through September 30, 2005
Inspectors:	J. Adams, Senior Resident Inspector D. Karjala, Resident Inspector R. Jickling, Emergency Preparedness Analyst M. Holmberg, Reactor Inspector M. Mitchell, Radiation Specialist M. Wilk, Reactor Engineer
Approved by:	R. Skokowski Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000282/2005008, 05000306/2005008; 07/01/2005 - 09/30/2005; Prairie Island Nuclear Generating Plant, Units 1 and 2; Heat Sink Performance.

This report covers a three-month period of baseline resident inspection and announced baseline inspection on emergency preparedness, heat sink performance, and occupational radiation safety. The inspection was conducted by the resident inspectors and inspectors from the Region III office. Three Green findings were identified, all of which involved violations of NRC requirements. 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 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control." The licensee failed to implement nondestructive examinations on the discharge piping of the safety-related cooling water pumps to verify that the pipe wall had not been reduced below minimum design thickness.

  This finding was more than minor because failure to monitor cooling water minimum pipe wall thickness could result in cooling water leakage or pipe rupture due to active corrosion and/or erosion processes present in the cooling water system. The finding was of very low safety significance because the licensee concluded that the piping systems were currently operable based on the absence of through-wall leakage and based upon the surface appearance of internal piping sections photographed during periodic pump discharge valve maintenance. (Section 1R07.b.1)

- Green. A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." The licensee failed to implement appropriate configuration and design controls associated with modifications made to the number 22 component cooling water (CC) heat exchanger (HX) divider plate. Specifically, the licensee failed to verify input of a key input assumption, apply appropriate acceptance criteria, and update drawings with the replacement divider plate material installed. As corrective actions, the licensee revised related modifications and calculations, and intends to examine CC HX welds during the next internal HX inspection.

  This finding was more than minor because the number 22 CC HX divider plate was modified, returned to service, and operated outside design allowable limits due to excessive differential pressure. Sustained operation outside design allowable limits could have resulted in divider plate failure and loss of heat exchanger function. The

finding was of very low safety significance because it was a design issue which did not result in loss of function per Generic Letter 91-18. (Section 1R07.b.2)

- Green. A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control.” The licensee failed to establish a test program to ensure that the design basis reserve makeup volume of cooling water for the ultimate heat sink contained in the intake canal was maintained. Specifically, the loss of reserve volume available in the intake canal due to accumulation/buildup of sediment was not being tracked or evaluated.

  This finding was more than minor because failure to monitor the loss of reserve volume available in the intake canal due to accumulation/buildup of sediment could have resulted in an inadequate cooling water reserve volume to support a plant shutdown and cooldown following a loss of Lock and Dam No. 3. The finding was of very low safety significance because the licensee demonstrated that adequate reserve volume existed in the intake canal to support the 4-hour reserve volume described in the Updated Safety Analysis Report. (Section 1R07.b.3)

B. Licensee-Identified Violations

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. This violation is listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near full power until September 16, 2005, when reactor power was reduced to 7.5 percent power to allow the main generator to be disconnected from the grid and the Unit 1 turbine shutdown. The reduction in power was conducted in order to balance the main generator to reduce vibrations. Unit 1 was restored to full power on September 18, 2005, and operated at or near full power for the remainder of the period.

Unit 2 operated at or near full power throughout the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors performed three inspection samples comprised of partial system walkdowns of accessible portions of trains of risk-significant mitigating systems equipment during times when the trains were of increased importance due to the redundant trains or other related equipment being unavailable. In addition, the inspectors reviewed corrective action program action requests (CAPs) associated with equipment alignment issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The inspectors utilized the valve and electric breaker checklists to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors also examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious performance deficiencies. The inspectors reviewed outstanding work orders (WO) and CAPs associated with the operable trains to verify that those documents did not reveal issues that could affect train function. The inspectors used the information in the appropriate sections of the Updated Safety Analysis Report (USAR) to determine the functional requirements of the systems.

The inspectors verified the alignment of the following trains:

- D1 diesel generator during the unavailability of the D2 diesel generator for surveillance testing on August 22, 2005;
- Unit 2 residual heat removal train B during the unavailability of the train A residual heat removal (RHR) for surveillance testing on September 14, 2005; and

- D1 diesel generator during the unavailability of the D2 diesel generator for surveillance testing on September 19, 2005.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

.2 Semiannual Complete System Walkdown

a. Inspection Scope

During the week of July 24, 2005, the inspectors performed a detailed in-plant walkdown of the alignment and condition of the Unit 2 safety-related onsite alternating current power sources (diesel generators) and their associated 4160 volt alternating current buses, load sequencers, and support systems. All components were risk significant components that provide emergency power to mitigating systems and other safety related loads during normal, off-normal, and accident modes of operation. This inspection effort constituted one complete system alignment inspection sample. In addition, the inspectors reviewed CAPs associated with equipment alignment issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The inspectors conducted in-plant walkdowns using the applicable alignment checklists and plant drawings to verify that system components were properly positioned to support the completion of system safety functions and to verify that the as-found system configuration matched the configuration specified in the system alignment checklist and plant drawings. The inspectors examined the material condition of the components, such as pumps, motors, valves, instrumentation, controls, bus relay settings, and electrical panels. The inspectors observed operating parameters of equipment to verify that there were no obvious performance deficiencies and examined all applicable outstanding design issues, temporary modifications, and operator workarounds. The inspectors verified that tagging clearances were appropriate and attached to the specified equipment where applicable. The inspectors reviewed outstanding WOs and CAPs associated with the trains to determine if any degraded conditions existed that could affect the accomplishment of the system's safety functions. The inspectors referred to the Technical Specification (TS), USAR, and other design basis documents to determine the functional requirements of the systems and verified those functions could be performed if needed. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Protection Area Walkdowns

a. Inspection Scope

The inspectors conducted in-office and in-plant reviews of portions of the licensee's Fire Hazards Analysis and Fire Strategies to verify consistency between these documents and the as-found configuration of the installed fire protection equipment and features in the fire protection areas listed below. The inspectors selected fire areas for inspection based on their overall contribution to internal fire risk, as documented in the Individual Plant Examination of External Events; their potential to impact equipment which could initiate a plant transient; or their impact on the plant's ability to respond to a security event. The inspectors assessed the control of transient combustibles and ignition sources, the material and operational condition of fire protection systems and equipment, and the status of fire barriers. In addition, the inspectors reviewed CAPs associated with fire protection issues to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

The following nine fire areas were inspected by in-plant walkdowns supporting the completion of nine fire protection zone walkdown samples:

- Fire Area 13, control room on July 25, 2005;
- Fire Area 22, 480 volt safety-related bus 121 room on July 22, 2005;
- Fire Area 26, D2 diesel generator room on July 22, 2005;
- Fire Area 33, 11 battery room on July 22, 2005;
- Fire Area 34, 12 battery room on July 22, 2005;
- Fire Area 35, 21 battery room on July 25, 2005;
- Fire Area 36, 22 battery room on July 25, 2005;
- Fire Area 101, D5 diesel generator engine room on July 25, 2005; and
- Fire Area 116, D6 diesel generator lubricating oil day storage tank room on July 25, 2005.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07B)

.1 Biennial Review of Heat Sink Performance

a. Inspection Scope

From July 11, 2005, through July 14, 2005, the inspectors performed an on-site review of documents related to the maintenance and/or performance testing of the auxiliary

feedwater system motor-driven pump lube oil coolers and the 12 and 22 component cooling water (CC) heat exchangers (HXs). These HXs were chosen for review based on their relatively high risk value in the licensee's probabilistic safety analysis.

While onsite, the inspectors reviewed completed surveillance tests and associated procedures for the selected HXs. The inspectors reviewed this documentation to confirm that the inspection or performance testing methodology was consistent with accepted industry and scientific practices such as Electrical Power Research Institute standard NP-7552, "Heat Exchanger Performance Monitoring Guidelines." The inspectors reviewed HX performance testing documentation to verify that acceptance criteria were consistent with design basis values, as outlined in the USAR and the TS requirements. The inspectors also reviewed eddy current examination reports and internal visual examination reports to evaluate the structural integrity of the heat exchangers. The inspectors performed a physical walkdown of these heat exchangers and discussed the status of these components with licensee engineers.

The inspectors reviewed documentation to verify performance of the ultimate heat sink (UHS). Specifically, the inspectors reviewed the availability of the UHS under adverse weather conditions (icing) and silting or bio-fouling conditions. This was done through review of licensee procedures and completed surveillance tests, or interviews with licensee engineers. The inspectors also performed a physical walkdown of the accessible plant intake structures and water reservoirs credited in the USAR for supplying the safety related cooling water (CL) systems (e.g., the UHS). These reviews were done to confirm that a program had been established and implemented consistent with licensee commitments to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

The inspectors reviewed condition assessment resolution documents associated with the selected HXs or those related to the UHS to verify that the licensee had an appropriate threshold for identifying issues. The inspectors also evaluated the effectiveness of the corrective actions for identified issues, including design changes and engineering justifications for operability. These reviews were done to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

The documents that were reviewed during this inspection are included at the end of the report.

The reviews as discussed above counted as two inspection samples.

b. Findings

.1 CL Pump Discharge Piping Wall Thickness Not Monitored

Introduction: The inspectors identified a finding involving a Non-Cited Violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," having very low safety significance (Green) for failure to perform nondestructive examinations (NDE) on the discharge piping of the CL pumps to verify that the pipe wall had not been reduced below minimum design thickness.

Description: Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," Action III, identified the need for a program to routinely inspect service water system piping for corrosion, erosion, protective coating failure, silting, and bio-fouling to ensure that service water system performance is not degraded. In Procedure H49, "Service Water and Fire Protection Inspection Program," the licensee established a program consistent with Generic Letter 89-13, Action III, that included use of ultrasonic examinations (UT) or radiography (RT) to identify pipe wall loss due to general corrosion, micro-biologically induced corrosion (MIC) or erosion processes. To support repetitive NDE measurements, the licensee typically marked external susceptible pipe sections with an inspection point grid.

On July 11, 2005, during a CL system walkdown, the inspectors identified a lack of external grid marks for locating points to measure pipe wall thickness readings. Specifically, the inspectors did not observe NDE grid points on pipe areas susceptible to erosion/corrosion such as downstream of pipe elbows on the discharge system piping for the safety-related CL pumps (Nos. 12, 22, and 121). The licensee subsequently determined that pipe wall thickness measurements had never been recorded for these piping sections and that pipe wall measurements were required because this piping was susceptible to corrosion and/or erosion as identified in Procedure H49. The licensee entered the issue into the corrective action program for assessment of needed corrective actions.

Analysis: The inspectors determined that the licensee's failure to implement the test program for measurement of pipe wall thickness on the discharge system piping of the safety-related CL pumps was a performance deficiency that warranted a significance evaluation. The inspectors reviewed this finding against the guidance contained in Appendix B, "Issue Dispositioning Screening," of IMC 0612, "Power Reactor Inspection Reports." The inspectors concluded that the finding was greater than minor because it was associated with the attribute of equipment performance, which affected the mitigating systems cornerstone objective of ensuring the availability and reliability of the CL system and if left uncorrected, it could have become a more significant safety concern. This finding could have become a more significant safety concern because failure to monitor cooling water minimum pipe wall thickness could result in cooling water leakage or pipe rupture due to active corrosion and/or erosion processes present in the CL system.

The inspectors determined that the finding could not be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," because the SDP for the mitigating systems cornerstone only applied to degraded systems/components, not to the procedures and processes designed to detect component degradation. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green). The inspectors concluded that the finding was of very low safety significance, because the licensee concluded that the piping systems were currently operable based on the absence of through-wall leakage and based upon the appearance of internal piping sections photographed during periodic pump discharge valve maintenance. The licensee engineer indicated that if substantive pipe wall loss due to erosion was occurring downstream of these check valves, it may be visually evident on the internal surfaces. The inspectors examined these photographs and noted

evidence of general corrosion and MIC tubercles and nodules, but agreed with licensee staff that no visual evidence of pipe wall erosion was present.

Enforcement: On July 11, 2005, while performing the baseline heat sink performance inspection procedure 71111.07, the inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

Title 10 CFR Part 50, Appendix B, Criterion XI, requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in the applicable design documents.

Section 5.1.1 of Procedure H49, "Service Water and Fire Protection Inspection Program," Revision 1, required, in part, that the primary method of examination to detect and measure MIC or nodule buildup is tangential RT. The primary method for sediment, cavitation and erosion may be either UT or RT.

Section 5.5.1 of Procedure H49, "Service Water and Fire Protection Inspection Program," Revision 1, required, in part, selecting examination locations in the service water system (also known as CL system) which are subject to intermittent flow, have a significant differential pressure or are subject to high velocity.

Contrary to the above, as of July 11, 2005, the licensee had not performed tests (UT or RT) to measure pipe wall loss from corrosion, erosion, or MIC within the discharge system piping (subject to intermittent flow, significant differential pressure and high velocity) for the safety-related CL pumps (Nos. 12, 22, and 121) in accordance with the written test Procedure H49. This violation has existed since the beginning of commercial plant operation (December 16, 1973, for Unit 1, December 21, 1974, for Unit 2). The finding is not suitable for SDP evaluation, but has been reviewed by NRC Management and is determined to be a Green finding of very low safety significance. 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 043408, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000282/2005008-01; NCV 05000306/2005008-01).

.2 Inadequate Design Control for the 22 CC HX Divider Plate Modifications

Introduction: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," having very low safety significance (Green) for failure to implement appropriate configuration and design controls associated with modifications made to the 22 CC HX divider plate.

Description: The licensee staff identified during past CL system operating configurations that the CC HXs were operated above the original design differential pressure (15 pounds per square inch differential (psid)) as evidenced by the identification of bowed support plates on the CL system (tube) side of these HXs. For the 22 CC HX, the licensee initially corrected this issue by welding in a stainless steel section of divider

plate with a single reinforcement bar (Modification 92L358, “CC HX Divider Plate Support,” completed on February 1, 1995) and had demonstrated (in Calculation

ENG-ME-044, “CC Heat Exchanger Divider Plate Support Loading,” Revision 0), that this new design would withstand a maximum differential pressure of 25 psid across the divider plate. The licensee selection of 25 psid as the maximum divider plate differential pressure load was based on informal (e.g., non-calibrated gauges) test data collected during the quarterly system flow test. However, on November 25, 1998, the licensee identified a bowed/bent divider plate and reinforcement support bar in the 22 CC HX and documented this condition in Nonconformance Report 19983244. In this nonconformance report, the licensee recorded that the divider plate had deflected upward by 9/16-inch and the divider plate reinforcement stiffener bar had also deflected/bent by 1/4-inch. The licensee determined that the cause of this deflection was a high differential pressure load across the divider plate which occurred during Phase II cooldown, when the HX flow control valve reached a full open position. Therefore, during the periods of plant operation in Phase II cooldown, the 22 CC HX divider plate stress exceeded design allowable limits as evidenced by the divider plate and stiffener bar deformation (e.g., material yielded).

The licensee corrective actions for the 22 CC HX bent divider plate included replacement of the bent portions of the divider plate material and installation of additional divider plate stiffener bars and installation of travel stops on the flow control valve to limit the full flow condition through the HX during Phase II cooldown. However, the licensee had not updated the CC HX drawings to reflect the installation of a stainless steel section of divider plate (installed per Modification 92L358). The licensee also did not evaluate the potential for galvanic corrosion of the stainless steel to carbon steel welds at the stiffener bars and at the replacement sections on the divider plate. Further, the licensee did not take actions to investigate why the modification process controls had failed (as evidenced by divider plate deformation), and thus no corrective actions had been initiated to correct the process errors that allowed this modification failure. The licensee captured these issues in CAPs 043424 and 043425 and intended to perform NDE on the affected welds during the next internal HX inspection.

To correct the original inadequate modification, the licensee issued a Revision 1 to Modification 92L358. In this revision, the licensee installed three additional stiffener bars to the CC HX divider plate and confirmed the adequacy of the new design in Calculation PI-S-021, “Reinforcing of CC HX Divider Plate.” However, the licensee used an incorrect acceptance criteria in this calculation for the maximum allowable material design stress. The licensee had selected an allowable stress (18,800 pounds per square inch (psi)) based upon a 100-degree operating temperature instead of using the lower allowable stress (17,400 psi) for the 200-degree operating temperature as was used in the original HX design. Additionally, in Calculation ENG-ME-526, “RHR and CC HX Capability During Post-LOCA [Loss of Coolant Accident] Recirculation,” the licensee identified that post-LOCA operating conditions would reach 144 degrees Fahrenheit in the CC HX at this location. Because the calculated divider plate bending stress at the maximum design differential pressure was 16,700 psi, the inspectors concluded that the error in selecting and applying the correct acceptance stress alone (e.g., not considered in conjunction with the error for maximum divider plate loading) did not affect divider plate operability. The licensee documented this error in CAP 043427.

The inspectors identified that the same differential pressure measured during the quarterly system flow test (without allowance for instrument uncertainty) was used in Revision 1 to Calculation PI-S-021. In this calculation, the licensee had also not accounted for the additional differential pressure induced by the 10 percent tube plugging which was allowed in the CC HX preventative maintenance procedures. Because of these issues, the inspectors were concerned that the 25 psi differential pressure established in Calculation PI-S-021, Revision 1, may not bound the maximum differential pressure which could be developed across the divider plate. The licensee documented this issue in CAP 043429 and performed additional calculations which indicated that maximum differential pressure should be around 16 psid with 10 percent of the CC HX tubes plugged to demonstrate divider plate operability. Because the 22 CC HX had been subject to a visual internal inspection which had not identified further divider plate bending after the last series of corrective actions (e.g., additional stiffener bars and HX flow control valve travel stops), and the heat exchanger did not contain any tube plugs, the inspectors did not have a current operability concern.

Analysis: The inspectors determined that the licensee's failure to perform adequate design reviews for the 22 CC HX divider plate modification was a performance deficiency that warranted a significance evaluation. The inspectors determined that the finding was more than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening," because it was associated with the attribute of design control, which affected the mitigating systems cornerstone objective of ensuring the availability and reliability of the 22 CC HX to respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform appropriate design reviews was considered more than minor, because the 22 CC HX divider plate was modified, returned to service, and operated outside design allowable limits due to excessive differential pressure. Sustained operation outside design allowable limits could have resulted in divider plate failure and loss of the 22 CC HX function.

The inspectors completed a significance determination of this issue using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening and determined that the inadequate design reviews implemented for the 22 CC HX divider plate modification was not a design issue resulting in a loss of function per Generic Letter 91-18, did not represent an actual loss of a system's safety function, and did not result in exceeding a TS allowed outage time. Therefore, the inspectors determined that the finding was of very low safety significance (Green).

Enforcement: On July 13, 2005, while performing the baseline heat sink performance inspection procedure 71111.07, the inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," required, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, procedures, and instructions.

Contrary to this requirement, as of July 13, 2005, the inspectors identified that the design reviews conducted for divider plate support modifications to the 22 CC HX (Modification 92L358, "Component Cooling Water Heat Exchanger Divider Plate Support," Revision 0

and Revision 1, Calculations ENG-ME-044, "Component Cooling Water Heat Exchanger Divider Plate Support Loading," Revision 0, and Calculation PI-S-021, "Reinforcing of CC HX Divider Plate," Revision 1) did not ensure the CC divider plate design basis was maintained and correctly translated into specifications, procedures, and instructions. Specifically, the licensee failed to verify a key input assumption (maximum divider plate differential pressure load), apply appropriate acceptance criteria (allowable bending stress), and failed to update drawings with the replacement divider plate material (stainless steel) installed. This violation has existed since February 1, 1995, when the divider plate modification was installed and the design was documented as complete in Modification 92L358. Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program, it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000306/2005008-02).

.3 <u>Loss of Makeup Reserve Volume Available in the Intake Canal Not Monitored</u>

<u>Introduction</u>: The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, having very low safety significance (Green) for failure to establish a test program to ensure that the design basis reserve makeup volume of cooling water for the UHS contained in the intake canal was maintained. Specifically, the licensee was not tracking or evaluating the loss of reserve volume available in the intake canal due to accumulation/buildup of sediment.

<u>Description</u>: For Prairie Island, the UHS includes the capability to shutdown and cooldown the plant following a failure of Lock and Dam No. 3 on the Mississippi River which would drop the water level available at the river intake screenhouse. To meet this design basis scenario, the UHS relies on a reserve makeup volume of cooling water present in the intake canal which is large enough to supply four hours of makeup water as discussed in USAR Section 10.4.1.2.2. The licensee staff had performed soundings to measure the water depth in the intake canals in accordance with a periodic Test Procedure (TP) 1690, "Approach, Intake, Recycle and Old Discharge Depth Sounding." However, the information gathered by the licensee staff was not being retained or used to confirm that the UHS reserve volume in the intake canal was being maintained. Specifically, the measured water depths recorded in TP 1690 were not required to be retained as plant records and therefore, the licensee staff could not trend accumulation of silt and debris in the intake canal. Further, TP 1690 did not require comparing the measured water depth in the intake canal against the minimum assumed in the design basis calculations which supported the four-hour makeup water reserve capacity.

The licensee staff located two completed copies of TP 1690 data recorded on September 25, 2000, and July 23, 2003. The inspectors identified that Step 7.6 had not been initialed as complete in these two procedure copies. This step required comparison of the depth readings with previous year readings to identify any significant changes. The inspectors concluded that even if this action had occurred, this criteria was subjective and would not identify a gradual accumulation of silt/debris that affected the reserve makeup capacity in the intake canal. The inspectors compared depth readings in the intake canal recorded in the 2003 TP 1690 data to the water depth assumed in the design basis Calculation ENG-ME-347, "Minimum Required Intake Bay Volume." Based upon this review, the inspectors identified that substantive silt/sediment

buildup had occurred, such that the assumed depth of the intake canal in this calculation was no longer valid. Specifically, in Calculation ENG-ME -347, the licensee assumed that for major areas of the intake canal, 10 feet of water depth was available and credited in the calculation of reserve volume. However, based upon the 2003 measured depths, less than 8.5 feet of water depth was available at normal water levels. To confirm UHS operability, the licensee staff performed a separate informal calculation which removed some conservative assumptions used in Calculation ENG-ME-347, and concluded that an adequate reserve volume currently existed to meet the four-hour reserve volume described in the USAR Section 10.4.1.2.2. The licensee entered the issue into the corrective action program for assessment of further corrective actions.

Analysis: The inspectors determined that the licensee's failure to implement a test program to track or evaluate the loss of reserve volume available in the intake canal due to accumulation/buildup of sediment was a performance deficiency that warranted a significance evaluation. The inspectors reviewed this finding against the guidance contained in Appendix B, "Issue Dispositioning Screening," of IMC 0612, "Power Reactor Inspection Reports." The inspectors concluded that the finding was greater than minor because it was associated with the attribute of equipment performance, which affected the mitigating systems cornerstone objective of ensuring the availability and reliability of the CL system and if left uncorrected, it could have become a more significant safety concern. This finding could have become a more significant safety concern because the failure to monitor the loss of reserve volume available in the intake canal due to accumulation/buildup of sediment could have resulted in an inadequate cooling water reserve volume to support a plant shutdown and cooldown following a loss of Lock and Dam No. 3.

The inspectors determined that the finding could not be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," because the SDP for the mitigating systems cornerstone only applied to degraded systems/components, not to deficiencies in the programs/procedures that are designed to detect system degradation. Therefore, this finding was reviewed by a Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green). The inspectors concluded that the finding was of very low safety significance, because the licensee demonstrated that adequate reserve volume existed in the intake canal to support the four-hour reserve volume described in the USAR.

Enforcement: On July 14, 2005, while performing the baseline heat sink performance Inspection Procedure 71111.07, the inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control."

Title 10 CFR Part 50, Appendix B, Criterion XI, requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in the applicable design documents.

Contrary to the above, as of July 14, 2005, the licensee had not established and implemented a test program to track or evaluate the loss of reserve volume in the intake

canal due to accumulation/buildup of sediment to ensure that the four-hour reserve volume as credited in USAR Section 10.4.1.2.2, would be maintained. This violation has existed since the beginning of commercial plant operation (December 16, 1973, for Unit 1, and December 21, 1974, for Unit 2). The finding is not suitable for SDP evaluation, but has been reviewed by NRC management and is determined to be a Green finding of very low safety significance. Because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (CAPs 043420 and 043446), it is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000282/2005008-03; 05000306/2005008-03).

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On August 24, 2005, the inspectors performed a quarterly review of licensed operator requalification training in the simulator, completing one licensed operator requalification inspection sample. The inspectors observed a crew during an evaluated exercise in the plant's simulator facility. The inspectors compared crew performance to licensee management expectations. The inspectors verified that the crew completed all of the critical tasks for each exercise scenario. For any weaknesses identified, the inspectors observed that the licensee evaluators noted the weaknesses and discussed them in the critique at the end of the session.

The inspectors assessed the licensee's effectiveness in evaluating the requalification program, ensuring that licensed individuals would operate the facility safely and within the conditions of their licenses, and evaluated licensed operator mastery of high-risk operator actions. The inspection activities included, but were not limited to, a review of high-risk activities, emergency plan performance, incorporation of lessons learned, clarity and formality of communications, task prioritization, timeliness of actions, alarm response actions, control board operations, procedural adequacy and implementation, supervisory oversight, group dynamics, interpretations of TS, simulator fidelity, and licensee critique of performance.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed repetitive maintenance activities to assess maintenance effectiveness, including maintenance rule (10 CFR 50.65) activities, work practices, and common cause issues. The inspectors performed two issue/problem-oriented maintenance effectiveness samples. The inspectors assessed the licensee's

maintenance effectiveness associated with problems on the following structures, systems, and components:

- valve CW-19-6, cooling water supply to instrument air compressors, which had a disc separation from the stem; and
- steam generator 22 power-operated relief valve that experienced leak-by following maintenance.

The inspectors reviewed the licensee's maintenance rule evaluations of equipment failures for maintenance preventable functional failures and equipment unavailability time calculations, comparing the licensee's evaluation conclusions to applicable Maintenance Rule (a)1 performance criteria. Additionally, the inspectors reviewed scoping, goal-setting (where applicable), performance monitoring, short-term and long-term corrective actions, functional failure definitions, and current equipment performance status.

The inspectors reviewed CAPs for significant equipment failures associated with electrical equipment problems for risk significant and safety-related mitigating equipment to ensure that those failures were properly identified, classified, and corrected. The inspectors reviewed other CAPs to assess the licensee's problem identification threshold for degraded conditions, the appropriateness of specified corrective actions, and that the timeliness of the actions were commensurate with the significance of the identified issues.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed risk assessments for three planned and two emergent maintenance activities associated with the following combinations of equipment unavailability completing five risk assessment and emergent work control inspection samples:

- the emergent failure of the 12 diesel-driven cooling water pump on July 19, 2005;
- the planned simultaneous unavailability of 23 charging pump and instrument air compressor cooling water source via valve CL 95-1, concurrent with maintenance on the Red Rock transmission line on July 26, 2005;
- the planned simultaneous unavailability of 11 component cooling water pump, the 11 component cooling water heat exchanger, instrument air compressor cooling water source via valve CL 95-1, and the D1 diesel generator on August 8, 2005;
- the emergent failure of the switchyard transformer CT-1 on August 19, 2005; and

- the planned simultaneous work on the D6 diesel generator 24-hour load test, the 22 turbine-driven auxiliary feedwater pump for Appendix R hot-wire work, and severe weather considerations on September 12, 2005.

During these reviews, the inspectors compared the licensee's risk management actions to those actions specified in the licensee's procedures for the assessment and management of risk. The inspectors verified that evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration where practical, and that contingency plans were in place where appropriate. The inspectors used the licensee's daily configuration risk assessment records, observations of shift turnover meetings, and observations of daily plant status meetings to verify that the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were communicated to the necessary personnel. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-Routine Plant Evolutions and Events (71111.14)

.1 Loss of Transformer CT-1

a. Inspection Scope

On August 19, 2005, the inspectors observed, from the control room, the operators' response to a loss switchyard bus 1 that resulted in the loss of the normal power supply to safety-related buses 16 (Unit 1) and 25 (Unit 2). Switchyard bus 1 isolated due to a lockout and fault on transformer CT-1. The inspectors compared the operators' response to the actions specified in applicable abnormal operating procedures and verified that the plant equipment responded as designed. The inspectors verified the timely performance of required surveillance test procedures, the entry into the appropriate TS Limiting Conditions for Operation, and the reassessment of on-line risk in accordance with the licensee's risk assessment procedures. The inspectors observed the licensee's initial troubleshooting and recovery actions and verified that the licensee appropriately entered problems into their corrective action program in accordance with plant procedures. The documents reviewed by the inspectors are listed in the Attachment. This observation and review of the CT-1 failure constituted one personnel performance related to non-routine plant events inspection sample.

b. Findings

No findings of significance were identified.

.2 Planned Reactor Shutdown to Mode 2 for Unit 1 Generator Balancing

a. Inspection Scope

On September 16, 2005, the inspectors observed licensee personnel perform a planned shutdown of Unit 1 to Mode 2 in order to balance the Unit 1 generator. This observation and review of the Unit 1 reactor shutdown constituted one personnel performance related to non-routine plant evolution inspection sample. The inspectors observed the performance of operations personnel in the control room during the planned but non-routine evolution. The inspectors compared the actions of plant personnel to the action required by TS and plant procedures. The documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of six operability evaluations completing six operability evaluation inspection samples. The inspectors conducted these inspections by in-office review of associated documents and in-plant observations of affected areas and plant equipment. The inspectors compared degraded or nonconforming conditions of risk-significant structures, systems, or components associated with mitigating systems against the functional requirements described in TS, the USAR, and other design basis documents; determined whether compensatory measures, if needed, were implemented; and determined whether the evaluation was consistent with the requirements of 5AWI 3.15.5, “Operability Determinations.” The following operability evaluations were reviewed:

- prompt operability evaluation of degraded door seals on the 11 and 21 battery room doors documented in CAP 043582 on July 25, 2005;
- Operability Recommendation (OPR) 000551, that documented the operability of the 11 and 22 turbine-driven auxiliary feedwater pump steam admission valves receiver capacity on August 1, 2005;
- OPR 000554, that documented the operability of the emergency core cooling system during recirculation with an unqualified epoxy coating on the control rod drive mechanism cooling fans on August 23, 2005;
- OPR 000547, that documented the operability of the 21 safety injection accumulator following the identification of cracking in the cladding on August 26, 2005;
- prompt operability evaluation of relevant chemical and volume control system valve following indications of boric acid leakage as documented in CAPs 043805 and 044237 on September 6, 2005; and
- prompt operability evaluation of D2 diesel generator with air supply problems to the cooling water inlet valve CV-31506 on September 9, 2005.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

a. Inspection Scope

On September 1, 2005, the inspectors reviewed an OWA associated with component cooling water supply lines to the 123 liquid nitrogen pump. The component cooling water supply piping was determined not to be seismically qualified and must be maintained under administrative controls with isolation valves in the closed position. This required two operations personnel to operate this pump.

Specifically, the inspectors evaluated if the operator's ability to implement abnormal and emergency operating procedures were affected by the OWA. The inspectors also reviewed OWAs for increased potential for personnel error including:

- required operations contrary to past training or require more detailed knowledge of the system than routinely provided;
- required a change from longstanding operational practices;
- required operation of system or component in a manner that is different from similar systems or components;
- created the potential for the compensatory action to be performed on equipment or under conditions for which it is not appropriate;
- impaired access to required indications, increase dependence on oral communications, or required actions under adverse environmental conditions; or
- required the use of equipment and interfaces that had not been designed with consideration of the task being performed.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors performed six assessments of post-maintenance testing completing six post-maintenance test inspection samples. The inspectors selected post-maintenance tests associated with important mitigating and barrier integrity systems to ensure that the testing was performed adequately, demonstrated that the maintenance was successful, and that operability of associated equipment and/or systems was restored. The

inspectors conducted this inspection by in-office review of documents and in-plant walkdowns of associated plant equipment. The inspectors observed and assessed the post-maintenance testing activities for the following maintenance activities:

- 12 diesel-driven cooling water pump following a failure of its bearing water supply on July 19, 2005;
- 21 containment spray discharge valve MV-32114 following repairs for dual position indication on August 8, 2005;
- CV-39415, cooling water supply valve for diesel generator D2 on August 12, 2005;
- 12 diesel-driven cooling water pump bearing water supply check valve from well water repair on September 7, 2005;
- 22 turbine-driven auxiliary feedwater pump following rewire of motor-operated valve for Appendix R hotshort considerations on September 13, 2005; and
- D5 diesel generator following the replacement of the fuel oil pump on engine 2 and motor damper MD-32422 on September 26, 2005.

The inspectors reviewed the appropriate sections of the TS, USAR, and maintenance documents to determine the systems' safety functions and the scope of the maintenance. The inspectors also reviewed CAPs to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action procedures.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

During this inspection period, the inspectors completed five surveillance inspection samples. Surveillance Procedure (SP) 2353A completed the quarterly inservice testing inspection requirement of a risk-significant valves. The inspectors selected the following surveillance testing activities:

- SP 2353A, Quarterly Testing of CS-47 and CS-49, 21 Containment Spray Pump Suction and Discharge Check Valves, Revision 6 on July 20, 2005;
- SP 1780, AMSAC (ATWS [Anticipated Transient Without Scram] Mitigating System Actuation Circuit) Quarterly Functional Test, Revision 8 on August 15, 2005;
- SP 1102, 11 Turbine-Driven Auxiliary Feedwater Pump Monthly Test, Revision 83 on September 8, 2005;
- SP 1106A, Monthly Testing of 12 Diesel-Driven Cooling Water Pump, Revision 65 on September 10, 2005; and

- SP 2155B, Quarterly Testing of Train B of Component Cooling System, Revision 11 on September 13, 2005.

During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to verify that:

- preconditioning did not occur;
- effects of the testing had been 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, properly documented, and the calibration frequency was in accordance with TS, 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 frequency met TS requirements to demonstrate operability and reliability;
- the 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/results were accurate, complete, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers (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 declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data have been accurately incorporated in the test procedure;
- 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 in the corrective action program.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted an in-office review of documentation associated with temporary modification 05T193 completing one temporary modification inspection

sample. Temporary modification 05T193 removed sand plugs from the Unit 2 loop A reactor coolant system cold leg nozzle and the loop A safety injection nozzle for the current operating cycle. As part of this inspection, the documents listed in the Attachment were utilized to evaluate the potential for an inspection finding.

The inspection activities included, but were not limited to, a review of design documents, safety screening documents, and the USAR to determine that the temporary modification was consistent with modification documents, drawings, and procedures. The inspectors also reviewed actual impact of the temporary modification on the permanent and interfacing systems. The inspectors also reviewed the CAPs listed in the Attachment to verify that the licensee was identifying issues at an appropriate threshold and entering them into their corrective action program in accordance with station corrective action.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

The inspectors discussed with Emergency Preparedness (EP) staff the operation, maintenance, and periodic testing of the ANS in the Prairie Island Nuclear Generating Plant's (PINGP) plume pathway Emergency Planning Zone to determine whether the ANS equipment was adequately maintained and tested in accordance with Emergency Plan commitments and procedures. The inspectors reviewed records of May 2003 through May 2005 monthly trend reports and siren test failures, as well as October 2003 through October 2004 maintenance checklists. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with plant EP staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an ERO activation to augment the on-shift ERO as well as the provisions for maintaining the plant's ERO call-out roster. The inspectors also reviewed reports and a sample of corrective action program records of unannounced off-hour augmentation tests, which were conducted June 23, 2005; April 13, 2005; March 15, 2005; December 8, 2004; August 28, 2004; April 1, 2004; November 3, 2003; July 1, 2003; and

April 10, 2003, to determine the adequacy of the drills' critiques and associated corrective actions. The inspectors also reviewed the EP training records of a sample of approximately one dozen Prairie Island ERO personnel, who were assigned to key and support positions, to determine whether they were currently trained for their assigned ERO positions. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed a sample of Nuclear Oversight staff's 2004 and 2005 audits of the Prairie Island Nuclear Generating Plant emergency preparedness program to verify that these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2004 biennial exercise, as well as various EP drills conducted in 2004, in order to verify that the licensee fulfilled its drill commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. Additionally, the inspectors reviewed a sample of EP items, corrective action program, and corrective actions related to the facility's EP program and activities to determine whether corrective actions were acceptably completed. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a licensed shift operating crew perform an "as-found" exercise on the simulator on August 3, 2005, completing one emergency planning simulator exercise sample. The inspectors observed activities in the control room simulator that include event classification and notification as well as the post-exercise critique. The inspectors evaluated the drill performance and verified that licensee evaluators' observations were consistent with those of the inspectors, and that deficiencies were entered into the corrective action program. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's occupational exposure control cornerstone performance indicators to determine whether or not the conditions surrounding the performance indicators had been evaluated, and identified problems had been entered into the corrective action program for resolution. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following three radiologically significant work areas within radiation areas, high radiation areas and airborne radioactivity areas in the plant and reviewed work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings and barricades were acceptable:

- High Integrity Container Sluicing Bay;
- Cask Decontamination Facility; and
- Unit 2 Containment Access.

This review represented one sample.

The inspectors walked down and surveyed (using an NRC survey meter) these three areas to verify that the prescribed radiation work permit, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers, if required, were properly located. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed eight corrective action reports related to access controls and one high radiation area radiological incident, a non-performance indicator identified by the licensee in high radiation areas less than 1 Roentgen per hour. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report. This review represented one sample.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the plant USAR to identify applicable radiation monitors associated with transient high and very high radiation areas including those used in remote emergency assessment. This review represented one sample. The inspectors identified the types of portable radiation detection instrumentation used for job coverage of high radiation area work, other temporary area radiation monitors currently used in the plant, continuous air monitors associated with jobs with the potential for workers to receive 50 millirem Committed Effective Dose Equivalent, whole body counters, and the

types of radiation detection instruments utilized for personnel release from the radiologically controlled area. This review represented one sample.

The inspectors verified calibration, operability, and alarm setpoint (if applicable) of the following seven instruments:

- Fast Scan Whole Body Counter;
- National Nuclear Corporation Friskall Personnel Monitor;
- Westinghouse Area Radiation Monitor;
- Nuclear Measurement Corporation Area Radiation Monitor;
- Eberline RO-20;
- Johnson Extender Model 200W; and
- Eberline RM-14

The inspectors determined what actions were taken when, during calibration or source checks, an instrument was found significantly out of calibration (greater than 50 percent), determined possible consequences of instrument use since last successful calibration or source check, and determined if the out of calibration result was entered into the corrective action program. There were no instances where the instrument was found significantly out of calibration. The inspectors also reviewed the licensee's 10 CFR Part 61 source term reviews to determine if the calibration sources used were representative of the plant source term. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, Licensee Event Reports (LERs), and Special Reports that involved personnel contamination monitor alarms due to personnel internal exposures to verify that identified problems were entered into the corrective action program for resolution. All event reports involving internal exposures greater than 50 millirem Committed Effective Dose Equivalent were reviewed to determine if the affected personnel were properly monitored utilizing calibrated equipment and if the data was analyzed and internal exposures properly assessed in accordance with licensee procedures. There were no internal exposures greater than 50 millirem during the inspection period. This review represented one sample.

The inspectors reviewed corrective action program reports related to exposure significant radiological incidents that involved radiation monitoring instrument deficiencies since the last inspection in this area. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being

conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk significant operational experience feedback.

This review represented one sample.

The inspectors determined if the licensee's self-assessment activities were identifying and addressing repetitive deficiencies or significant individual deficiencies that were identified in problem identification and resolution. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Radiation Protection Technician Instrument Use

a. Inspection Scope

The inspectors determined if the calibration expiration and source response check data records on radiation detection instruments staged for use were current, and observed radiation protection technicians for appropriate instrument selection and self-verification of instrument operability prior to use. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Self-Contained Breathing Apparatus (SCBA) Maintenance and User Training

a. Inspection Scope

The inspectors reviewed the status and surveillance records of SCBAs staged and ready for use in the plant and inspected the licensee's capability for refilling and transporting SCBA air bottles to and from the control room and operations support center during emergency conditions. The inspectors determined if control room operators and other emergency response and radiation protection personnel were trained and qualified in the use of SCBAs (including personal bottle change-out). The inspectors determined if at least three individuals on each control room shift crew, and three individuals from each

designated department were currently assigned emergency duties (e.g., onsite search and rescue duties). This review represented one sample.

The inspectors did not review the qualification documentation for at least 50 percent of the onsite personnel designated to perform maintenance on the vendor-designated vital components because the licensee does not conduct maintenance on vital components. All maintenance is conducted by the manufacturer qualified field representatives as necessary. Additionally, the inspectors reviewed the vital component maintenance records over the past five years for three SCBA units currently designated as "ready for service." The inspectors also ensured that the required, periodic air cylinder hydrostatic testing was documented and up to date, and that the Department of Transportation required retest air cylinder markings were in place for these three units. Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report. This review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Cornerstone: Emergency Preparedness

.1 Emergency Preparedness Strategic Areas

a. Inspection Scope

The inspectors reviewed the licensee's records associated with the three EP performance indicators listed below. The inspectors verified that the licensee accurately reported these indicators in accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC. Specifically, the inspectors reviewed licensee records associated with performance indicator data reported to the NRC for the period July 2004 through March 2005. Reviewed records included: procedural guidance on assessing opportunities for the three performance indicators; assessments of performance indicator opportunities during predesignated Control Room Simulator training sessions, the 2004 biennial exercise, and other drills; revisions of the roster of personnel assigned to key ERO positions; and results of periodic ANS operability tests. The following performance indicators were reviewed:

Common

- ANS;
- ERO Drill Participation; and
- Drill and Exercise Performance.

Key documents used by the inspectors in conducting this inspection are listed in the Attachment to this inspection report.

b. Findings

No findings of significance were identified.

Cornerstone: Occupational Radiation Safety

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspector reviewed the licensee's determination of performance indicator for the occupational radiation safety cornerstone (Occupational Exposure Control Effectiveness) to verify that the licensee accurately determined these performance indicators and had identified all occurrences required by these indicators. Specifically, the inspector reviewed the licensee's corrective action documents for 4th quarter 2004 and the first two quarters of 2005 Occupational Exposure performance indicator data to ensure that there were no performance indicator occurrences that were not identified by the licensee. Additionally, as part of plant walkdowns (Section 2OS1.1), the inspectors selectively examined the adequacy of posting and controls for locked high radiation areas, to verify the current Occupational Exposure Control Effectiveness performance indicator. The inspectors interviewed members of the licensee's staff who were responsible for performance indicator data acquisition, verification and reporting, to verify that their review and assessment of the data was adequate. This review represented one sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As 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 corrective action program at an appropriate threshold, that adequate attention was given to ensure timely corrective actions, and that adverse trends were identified and addressed. This does not count as an annual sample.

b. Findings

No findings of significance were identified.

.2 Annual Problem Identification and Resolution Sample

a. Inspection Scope

The inspectors selected an issue associated with the non-code repairs to three of the four containment fan coil units in the Unit 2 containment that ultimately resulted in a TS-required shutdown. This event was documented in CAPs 041535 and 042044 as well as Root Cause Evaluation (RCE) 000196. The inspectors' assessment of the licensee's corrective actions to correct these conditions constitutes one annual problem identification and resolution inspection sample.

The inspectors conducted a review of the previously referenced CAPs and other related corrective action program documents in order to assess the effectiveness of the licensee's efforts to correct the identified problem. The inspectors placed particular attention on the review of the licensee's corrective actions taken to address the noted deficiencies and the effectiveness of those actions. The inspectors also ensured that the licensee had identified the full extent of the issue, conducted an appropriate evaluation, and that licensee-identified corrective actions were appropriately prioritized. The key documents reviewed by the inspectors associated with this inspection are listed in the Attachment to this inspection report.

b. Findings and Observations

No findings of significance were identified.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000306/2005-001-00: Unit 2 Shutdown Required by TSs Due to Two Trains of Containment Cooling Inoperable.

On March 28, 2005, the licensee identified that potential non-code repairs had been made on the 21, 22, and 23 containment fan coil units (CFCU) since January of 2005. These repairs involved the performance of an braze overlay. It was determined that the repair may not have removed the flaw and was not performed in accordance with a code approved weld repair. On March 30, 2005, an operability recommendation performed by the licensee determined that the CFCUs were not operable and Unit 2 was shutdown. ASME Code repairs were completed on April 30, 2005. The condition was entered into the licensee's corrective action program with CAP 041535 and was the subject of RCE 000196. The RCE determined that planners and technical reviewers lacked knowledge and understanding that led to the selection of an unapproved repair procedure. Corrective actions to prevent recurrence included a code approved repair and training actions to correct limitations on the knowledge level of those in positions that would be involved in future repairs. The inspectors concluded that the licensee's selection and implementation of a non-code approved repair method constituted a violation of NRC requirements of very low safety significance. Since the licensee self-identified the issue, this LER is closed to the licensee identified finding described in Section 4OA7 of this report.

.2 (Closed) LER 05000306/2005-002-00: Unit 2 Shutdown Required by TSs Due to an Inoperable Emergency Diesel Generator.

On April 11, 2005, the Unit 2 diesel generator D5 was removed from service for a monthly slow start surveillance test. The test was halted on indications of high crankcase pressure on engine 2. The test procedure specifies the shutting down of the engine in the event that crankcase pressure exceeds 30 millimeters for more than a few minutes. During the test, a crankcase pressures as high as 48 millimeters was observed before the engine was unloaded. Technical Specifications 3.8.1, Required Action B.4 required returning the inoperable diesel generator to an operable status within seven days. The licensee's assessment of the scope of work to return the engine to an operable status indicated that the repairs could not be completed within the seven-day allowed outage time and Unit 2 was shut down on April 14, 2005. The licensee entered the failure of the engine into their corrective action program with CAP 041730 and 041810. Corrective actions completed include the rebuild of both engine 1 and 2 and vendor evaluation of removed pistons and cylinder liners. D5 was returned an operable status on April 25, 2005. Additionally the licensee has initiated RCE 000199 which has yet to be completed. A review of the D5 failure by inspectors did not identify any performance deficiencies and therefore no findings. This issue is closed.

.3 (Closed) LER 05000306/2005-003-00: Declaring Train of Containment Cooling Operable with One Fan Cooler Isolated Prohibited by TSs.

On February 11, 2005, the licensee identified leaks in the 22 and 23 CFCUs. Since the 22 CFCU is Train B and the 23 CFCU is Train A containment cooling, both trains of containment cooling were declared inoperable. Since TS 3.6.5 contains no condition for two trains of containment inoperable, the licensee entered TS Limiting Condition for Operation 3.0.3. The licensee performed an operability evaluation that concluded that the 21 CFCU, by itself, could remove the required post-accident heat load from containment and declared Train A of containment cooling operable on that basis and exited TS Limiting Condition for Operation 3.0.3. The inspectors concluded that the licensee's action constituted a violation of TSs since the TSs Surveillance Requirements 3.6.5.2 and 3.6.5.3 could not be met for both CFCUs in the A Train with the 23 CFCU isolated. The licensee completed repairs and returned the two CFCUs to operable status on February 12, 2005. The significance evaluation resulted in a finding of very low safety significance since the unavailability of the CFCUs did not adversely affect core damage frequency nor did it adversely affect the large early release frequency. The associated Green finding and NCV were issued in Inspection Report 05000282/2005003; 05000306/2005003, Section 1R15. The licensee entered the violation of NRC requirements into their corrective action program with CAP 043015. This issue is closed.

4OA6 Meeting(s)

.1 Exit Meeting

The inspectors presented the inspection results to Mr. R. Graham and other members of licensee management at the conclusion of the inspection on September 29, 2005. The

inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Emergency Preparedness Inspection with Mr. L. Clewett on July 1, 2005.
- Heat Sink Performance Biennial Inspection with Mr. R. Graham on July 14, 2005.
- Occupational Radiation Safety Inspection with Mr. R. Graham on August 5, 2005.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance was identified by the licensee and was a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Barrier Integrity

During a corrective action program review to address recurring pin hole leaks in the Unit 2 CFCU, the licensee identified that non-code repairs had been conducted on the 21, 22, and 23 CFCUs. The existence of non-code repairs was entered in the licensee's corrective action program with CAP 041535 and Unit 2 was shutdown to perform ASME Code repairs of the affected CFCUs. 10 CFR Part 50.55a(g)4 required, in part, that throughout the service life of a boiling or pressurized water reactor facility, components classified as ASME Code Class 1, 2 and 3 must meet requirements of ASME Code Section XI. ASME Code Section XI, IWA-4400(a), required that all welding (includes brazing activities) shall be performed in accordance with Weld Procedure Specifications that have been qualified by the owner. Contrary to these requirements, the license performed repairs to the 21 CFCU on January 11, 2005; to the 22 and 23 CFCUs on February 11, 2005; and to the 23 CFCU on March 26, 2005, without using a qualified weld/brazing procedure specification. The significance of the licensee identified finding was determined to be of very low safety significance since the unavailability of the CFCUs did not adversely affect core damage frequency nor did it adversely affect the large early release frequency.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Anderson, Radiation Protection and Chemistry Manager
M. Agen, Emergency Preparedness Coordinator
J. Callahan, Emergency Planning Manager
L. Clewett, Plant Manager
M. Davis, Regulatory Affairs Analyst
K. Den Herder, Engineer
T. Downing, Engineering Programs Supervisor
R. Graham, Director of Site Operations
P. Huffman, Operations Manager
J. Kivi, Licensing Engineer
J. Lash, Training Manager
K. Ludwig, Maintenance Manager
J. Maki, Outage and Scheduling Manager
S. McCall, Site Engineering Director (Acting)
C. Mundt, Engineering Design Manager
S. Northard, Bussiness Support Manager
T. Palmisano, Site Vice President
E. Perry, NOS Supervisor
A. Qualantone, Security Manager
M. Runion, Engineering Plant and Systems Manager
G. Salamon, Regulatory Affairs Manager
C. Sansome, Engineer
S. Thomas, Engineering Supervisor
M. Vonk, NMC Sr. Emergency Preparedness Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000282/2005008-01; 05000306/2005008-01	NCV	Failure to Monitor Cooling Water Pump Discharge Piping Wall Thickness
05000306/2005008-02	NCV	Inadequate Design Control for the 22 CC HX Divider Plate Modifications
05000282/2005008-03; 05000306/2005008-03	NCV	Failure to Monitor Loss of Makeup Reserve Volume Available in Intake Canal
05000306/2005-001-00	LER	Unit 2 Shutdown Required by TSs Due to Two Trains of Containment Cooling Inoperable
05000306/2005-002-00	LER	Unit 2 Shutdown Required by TSs Due to an Inoperable Emergency Diesel Generator

05000306/2005-003-00	LER	Declaring Train of Containment Cooling Operable with One Fan Cooler Isolated Prohibited by TSs

Discussed:

None.

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.

1R04 Equipment Alignment

Partial System Walkdown

Unit 1 D1 Diesel Generator Walkdown

Alignment Checklists C1.1.20.7-1; D1 Diesel Generator Valve Status; Revision 20
Alignment Checklists C1.1.20.7-2; D1 Diesel Generator Auxiliaries and Room Cooling; Revision 9
Alignment Checklists C1.1.20.7-3; Diesel Generator D1 Main Control Room Switch and Indicating Light Status; Revision 15
Alignment Checklists C1.1.20.7-4; D1 Diesel Generator Circuit Breakers and Panel Switches; Revision 12
CAP 043421; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
Condition Evaluation (CE) 008366 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
CE 008367; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
CE 008368; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
CE 008371; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
Corrective Action (CA) 011474; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed
CA 011475; 2M Transformer Deluge DM-4, Isolation Valve 2FP-5-1 Found Closed

Unit 2 Train A RHR Walkdown

Checklist C1.1.15-2; Unit 2 Residual Heat Removal; Revision 28
SP 2089B; Train B RHR Pumps and Suction Valves from the Refueling Water Storage Tank Quarterly Test; Revision 7
CAP 043800; Foreign Material Found In 21 RHR Pit During SP 2089A
CE 008625; Foreign Material Found In 21 RHR Pit During SP 2089A
Residual Heat Removal Integrated Checklist C1.1.15-2

Unit 1 D1 Diesel Generator Walkdown

Alignment Checklists C1.1.20.7-1; D1 Diesel Generator Valve Status; Revision 20
Alignment Checklists C1.1.20.7-2; D1 Diesel Generator Auxiliaries and Room Cooling; Revision 9
Alignment Checklists C1.1.20.7-3; Diesel Generator D1 Main Control Room Switch and Indicating Light Status; Revision 15

Alignment Checklists C1.1.20.7-4; D1 Diesel Generator Circuit Breakers and Panel Switches; Revision 12

Complete System Walkdown

All open Work Orders associated with the safety-related 4160 volt alternating current, and the safety-related onsite power sources as of August 5, 2005
All open corrective action program action requests with the safety-related 4160 volt alternating current, and the safety-related onsite power sources as of August 5, 2005
Operating Procedure 2C37.10; D5/D6 Diesel Generator Building Ventilation; Revision 3
D5 and D6 Diesel Generator Integrated Alignment Checklists C1.1.20.7-10, C1.1.20.7-11, C1.1.20.7-12, C1.1.20.7-13, C1.1.20.7-14, C1.1.20.7-15, and C1.1.20.7-16
Prairie Island D5 and D6 Flow Diagrams NF 118240 through NF 118252
CAP 043671; D1 and D2 Jacket Cooler Heater Temperature Switch Orientation

1R05 Fire Protection

Plant Safety Procedure F5, Appendix A; Fire Strategies for Fire Areas13, 22, 26, 33, 34, 35, 36, 101, and 116
Plant Safety Procedure F5, Appendix F, Revision 20; Fire Hazard Analysis for Fire Areas 13, 22, 26, 33, 34, 35, 36, 101, and 116
Plant Safety Procedure F5, Appendix K; Fire Detection and Protection Systems; Revision 9
Individual Plant Examination of External Events NSPLMI-96001, Appendix B; Internal Fires Analysis; Revision 2
CAP 043555; Found Diesel-Driven Fire Pump Strainer in Manual
CAP 043580; Cribbing in Auxiliary Building

1R07 Heat Sink Performance

Calculations

ENG-ME-526; RHR and CC HX Capability During Post-LOCA Recirculation; Revision 0, Addendum 1
99-131; Determination of Component Cooling Water Heat Exchanger Design Basis; Revision B
MECH-0268.4; Verification of Heat Removal Capability of the American Standard Heat Exchanger, Model 02030-EF; Revision 0
ENG-ME-347; Minimum Required Intake Bay Volume; Revision 1
ENG-ME-044; CC Heat Exchanger Divider Plate Support Loading; Revision 0
PI-S-021; Reinforcing of CC HX Divider Plate; Revision 0

Corrective Action Reports Reviewed During the Inspection

CAP 026911; Resolve High Positive Uncertainty for the 12 CC HX; dated December 1, 2002
CAP 027131; 12 CC HX Is in Standby With a Temperature of 55 Degrees; dated December 9, 2002

CAP 024150; Possible Formation of Sand-Bar in Front of Intake Screenhouse; dated July 12, 2002
CAP 035183; Valve CW-20-8, 22 CC HX Water Inlet Drain Line Plugged; dated February 3, 2004
CAP 003488; 21 Auxiliary Feedwater Suction Line Has MIC Influencing Bacteria Present; dated January 14, 2004
CAP 003858; Monthly Backflush of the Emergency Intake Line Can't Be Performed as Written; dated September 17, 2004
CAP 037675; 11/12 CC HX Outlet Flow Instruments Out of Tolerance; dated July 26, 2004
CAP 042279; U2 CC HX Performance Test Was Not Performed at the Start of Outage; dated May 5, 2005
CAP 040458; Large Number of Dead Fish in the Plant Screenhouse Fish Basket; dated January 6, 2005
Operating Experience (OE) 025872; Icing in Cooling Water Intake Line Resulted in Power Reduction and Manual Shutdown; dated April 15, 2003
Notebook Attachment for Issue Number 19983244; dated October 10, 1999

Corrective Action Reports Generated Due to the Inspection

CAP 043420; Intake Canal Depth Review - Sign-off Not Completed in TP 1690; dated July 13, 2005
CAP 043446: Measured Intake Canal Depth Does Not Match Drawing and Calculation Input; dated July 14, 2005
CAP 043408; Discharge Piping of 11/12/21/22/121 CL Pumps Have Not Been Inspected Using UT; dated July 12, 2005
CAP 043425; CC HX Drawings Not Updated to Reflect Divider Plate Material; dated July 13, 2005
CAP 043424; CC HX Divider Plate Attachment Weld Condition; dated July 13, 2005
CAP 043427; Calculations Related to Modification 92L358 Used Incorrect Allowable Stress; dated July 13, 2005
CAP 043429; No Tube Plugging Limits Calculation for CC HX That Address Max DP on Divider Plate; dated July 13, 2005

Heat Exchanger Specifications

SS-M-556(NSP); Standard Specification for Shell and Tube HX; not dated
SS-M-557(NSP); Specific Specification for Shell and Tube HX; not dated
SS-M-541(NSP); Specific Specification for Auxiliary Feedwater (AFW) Feedwater Pump; dated June 30, 1970
Heat Exchanger Specification Sheet, Lube Oil Cooler; dated April 22, 1970
Heat Exchanger Specification Sheet, Lube Oil Cooler; dated May 6, 1987
Heat Exchanger Specification Sheet; dated April 30, 1970

Miscellaneous Documents

Record of Eddy Current Inspection of Unit 1 Auxiliary Feedwater Pump Oil Coolers #11 and #12; dated January 17, 1996 and January 25, 1996

Record of Eddy Current Inspection of Unit 1 Auxiliary Feedwater Pump Oil Coolers #11 and #12; dated April/May of 1999
NMC-PB1-2-5; CC HX 12 ET Report; dated November 27, 2002
NMC-PB1-2-5; CC HX 22 ET Report; dated May 23, 2005
Component Cooling Water HX 22 Inspection Report; dated May 23, 2004
Component Cooling Water HX 22 Inspection Report; dated November 20, 2002
Drawing 69G-229-1-2E; Items 12 and 22 Shell and Channel Details; Revision C

Modifications and Design Changes

86L898; Auxiliary Feedwater Pump Lube Oil Cooing Modifications Unit 1 and Unit 2; Revision 0
92L358; Component Cooling Water HX Divider Plate Support; Revision 0
92L358; Component Cooling Water HX Divider Plate Support; Revision 1

Procedures

H21; Generic Letter 89-13 Implementing Program; Revision 10
H49; Service Water and Fire Protection Inspection Program; Revision 1
PM 3119-2-12; 12 CC HX Refueling Inspection; Revision 17
PM 3119-2-22; 22 CC HX Refueling Inspection; Revision 17
PM 3133-1-12; 12 Motor-Driven AFW Pump Inspection; Revision 17
SP 1617; Component Cooling Heat Exchanger Quarterly Test; Revision 23
SP 1304; Unit 1 Component Cooling HX Performance Test; Revision 6
SP 2304; Unit 2 Component Cooling HX Performance Test; Revision 5
SP 1329; 12 Motor-Driven AFW Pump Bearing Temperature Test; Revision 9
TP 1690; Approach, Intake, Recycle, and Old Discharge Canal Depth Sounding; Revision 3

Surveillances (completed)

SP 1304; Unit 1 CC HX Performance Test; dated September 11, 2004
SP 1304; Unit 1 CC HX Performance Test; dated October 16, 2002
SP 2304; Unit 2 CC HX Performance Test; dated September 17, 2003
SP 2304; Unit 2 CC HX Performance Test; dated February 7, 2002
TP 1690; Approach, Intake, Recycle, and Old Discharge Depth Sounding; dated September 25, 2000
TP 1690; Approach, Intake, Recycle, and Old Discharge Depth Sounding; dated July 23, 2003
PM 3119-2-12; CL/FP Pipe or CC HX Internal Inspection; dated December 26, 2002

Work Orders

9812770; Install Divider Plate Stiffeners on 12 CC HX; dated May 4, 1989
9812770; Install Divider Plate Stiffeners on 12 CC HX; dated April 30, 1999
9812597; Replace the 22 CC HX Divider Plate; dated November 28, 1998
9812628; Install Stiffener Bars to the 22 CC HX Divider Plate; dated November 28, 1998

1R11 Licensed Operator Requalification Program

Simulator Evaluation Guide P9160S-001SQ-50; Revision 0
5AWI 3.15.0; Plant Operation, Revision 17

1R12 Maintenance Effectiveness

Valve CW-19-6

CAP 042512; CW-19-6, Supply to Station Air Compressor Aftercooler Disc and Stem Separated
CAP 042598; Unit 1 Equipment Failure Causes PRA [Probabilistic Risk Assessment] Orange Category
CAP 042613; PRA Orange Category Not Initially Recognized or Assessed
Maintenance Rule Evaluation (MRE) 000463; PRA Orange Category Not Initially Recognized or Assessed
Apparent Cause Evaluation (ACE) 008966; PRA Orange Category Not Initially Recognized or Assessed
Maintenance Rule System Specific Basis Document; Cooling Water; Revision 11

22 Steam Generator Power Operated Relief Valve

CAP 043070; Unplanned TS Entry for 22 Steam Generator Power Operated Relief Valve on June 14, 2005
MRE 000472; Unplanned TS Entry for 22 Steam Generator Power Operated Relief Valve on June 14, 2005
ACE 008980; Unplanned TS Entry for 22 Steam Generator Power Operated Relief Valve on June 14, 2005
CA 011025; Unplanned TS Entry for 22 Steam Generator Power Operated Relief Valve on June 14, 2005
CA 011026; Unplanned TS Entry for 22 Steam Generator Power Operated Relief Valve on June 14, 2005
Maintenance Rule System Specific Basis Document; Main Steam; Revision 11

1R13 Maintenance Risk Assessments and Emergent Work Control

Emergent Failure of the 12 Diesel-Driven Cooling Water Pump

Unit 1 Risk Assessment for July 19, 2005 (Post-Failure)
CAP 043485; Unplanned Limiting Condition for Operation - 12 Diesel-Driven Cooling Water Pump Low Bearing Water Flow
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9
SP 2305 and 2335, and Risk Assessment for Proposed Work for Week of 54411B

23 Charging Pump, CL 95-1, and Red Rock Line Maintenance

Unit 2 Risk Assessment for July 26, 2005
CAP 042488; Unit 1 Probabilistic Risk Assessment Core Damage Frequency Calculation Incorrect for May 16 - 17, 2005 for Maintenance Rule (a)4 Equipment Unavailable
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9

D1, 11CCW Pump and Heat Exchanger, CL 95-1 with a Severe Thunderstorm Warning

Unit 1 Risk Assessment for August 8, 2005
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9

CT-1 Emergent Failure

Unit 1 and 2 Risk Assessment for August 19, 2005
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9
CAP 044022; CT-1 Transformer Locked Out and Caused Site Transient

Unit 2 Turbine-Driven Auxiliary Feedwater Pump Unavailability with Testing of D6 Diesel Generator and Severe Weather

SP 2305; D6 Diesel Generator Monthly Slow Start Test; Revision 25
SP 2335; D6 Diesel Generator 18 Month 24 Hour Load Test; Revision 11
Unit 2 Risk Assessment for September 12, 2005
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9

1R14 Non-Routine Evolutions

Loss of Switchyard Bus 1 Due to a Failure of CT-1

Abnormal Operating Procedure C20.3 AOP 3; Electrical Power System Operating Restrictions and Limitations of the 2RS Transformer; Revision 7
Abnormal Operating Procedure C20.3 AOP 6; Electrical Power System Operating Restrictions and Limitations Loss of CT-1 Transformer; Revision 8
Abnormal Operating Procedure C20.3 AOP 8; Electrical Power System Operating Restrictions and Limitations Loss of CT-11 Transformer; Revision 7
Abnormal Operating Procedure C20.3 AOP 10; Electrical Power System Operating Restrictions and Limitations Loss of 345 kV Bus 1; Revision 7
Technical Specification and TS Surveillance Requirement 3.8.1
Procedure H24.1; Assessment and Management of Risk Associated with Maintenance Activities; Revision 9
Risk Assessments for Unit 1 and 2 for September 19, 2005
Operating Logs for September 19, 2005

CAP 044032; CT-1 Transformer Locked Out and Caused a Site Transient

CAP 044035; Procedure Deficiency
CAP 044038; CT 11-1 Did Not Automatically Open
CAP 044048; Inoperable Offsite Electrical Path Causes Unplanned Limiting Condition for Operation Entry on Both Units

Unit 1 Planned Shutdown

Operating Procedure 1C1.3; Unit 1 Shutdown; Revision 55
Operating Procedure 1C1.4; Unit 1 Power Operation; Revision 39

1R15 Operability Evaluations

CAP 043582

USAR, Appendix I; Postulated Pipe Failure Outside Containment; Revision 26
Design Basis Document TOP-05; Hazards; Revision 2
Procedure H27; Control of Steam Exclusion Boundaries; Revision 8
Calculation PI-P602232-1000; Turbine Building Damper and Boundary Leakage; Revision 0
CAP 043582; 11/21 Battery Room Air Flow Through Door

OPR 000551

CAP 043013; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CAP 042775; Design Basis for the Air Receivers for CV-31998 and CV-31999 is Unclear
CA 011038; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CA 011039; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CA 010984; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CA 011032; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CA 011036; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CA 011037; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CE 008160; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
CE 008161; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
Operable But Degraded Evaluation 000139; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
OPR 000551; Clarify Design Basis for the Air Receivers for CV-31998 and CV-31999
Engineering Calculation ENG-ME-621; CV-31998 and CV-31999 Air Receiver Capacity; Revision 0

OPR 000554

CAP 044061; 10CFR21 Notification from Howden Buffalo May Affect Unit 2 CRDM Fan Coating Qualification
OPR 000554; 10CFR21 Notification from Howden Buffalo May Affect Unit 2 CRDM Fan Coating Qualification

OPR 000547

CAP 042802; Visual Evidence of Cracking in 21 Accumulator Cladding
OPR 000547; Visual Evidence of Cracking in 21 Accumulator Cladding

11 RHR and D2 Diesel Generator Operability

CAP 044018; 11 RHR Pump Removed from Service While D2 Cooling Water Air Operated Valve was Degraded
CAP 043924; CV-31506 Air Supply Regulator Failed
CE 008762; 11 RHR Pump Removed from Service While D2 Cooling Water Air Operated Valve was Degraded
ACE 009010; SV-33187 Failed to Open During Post-Maintenance Test for WO 0508940
ACE 009014; 11 RHR Pump Removed from Service While D2 Cooling Water Air Operated Valve was Degraded

1R16 OWAs

Listing of Open OWAs as of September 1, 2005
Prairie Island Operator Workaround Aggregate Impact Evaluation dated August 2005
CAP 037747; Non-Seismic Equipment in Component Cooling Water System Pressure Boundary
CAP 042764; 123 Liquid Nitrogen Pump Operation
CE 005702; Non-Seismic Equipment in Component Cooling Water System Pressure Boundary
CE 008044; 123 Liquid Nitrogen Pump Operation
CA 011074; 123 Liquid Nitrogen Pump Operation
Operable But Degraded Evaluation 000109; 123 Liquid Nitrogen Pump Operation
OPR 000509; Non-Seismic Equipment in Component Cooling Water System Pressure Boundary
Design Basis Document SYS-14; Component Cooling Water

1R19 Post-Maintenance Testing

12 Diesel-Driven Cooling Water Pump

Operating Procedure C35; Cooling Water System; Revision 58
SP 1834; Test Three-Way Valve Actuation to Cooling Water Supply for 12 Diesel-Driven Cooling Water Pump Bearing Water; Revision 2
WO 0506465; Clear and Unclog Lines and Valves for 12 Diesel-Driven Cooling Water Pump
CAP 043485; Unplanned Limiting Condition for Operation - 12 Diesel-Driven Cooling Water Pump Low Bearing Water Flow

MV-32114 Dual Indication

SP 2090A; 21 Containment Spray Pump Quarterly Test; Revision 5
WO 0506153; Adjust Limits and Replace Aux Contacts if Required on MV-32114

CAP 043346; 21 Containment Spray Pump Discharge MV-32114 Dual Indication During SP 2090A

CV-39415, D2 Cooling Water Supply Valve

CAP 043941; SV-33187 (D2 Cooling Water Supply CV) Failed to Open During PMT for WO 0508940
CAP 043950; CV-39415, Cooling Water Supply CV Opened Faster Than the Reference Range

12 Diesel-Driven Cooling Water Pump Bearing Water Supply Check Valve

SP 1845; Test Three-Way Valve Actuation to Cooling Water Supply for 12 Diesel-Driven Cooling Water Pump Bearing Water; Revision 2
CAP 044069; 12 Diesel-Driven Cooling Water Pump Three-Way Valve Problem Due to Supply Check Valve Installed Backwards
CE 008790; 12 Diesel-Driven Cooling Water Pump Three-Way Valve Problem Due to Supply Check Valve Installed Backwards

MV-32030, 22 Turbine-Driven Auxiliary Feedwater Cooling Water Supply Valve

CAP 034537; Appendix R: IN 92-18 “Hot Short” Concerns for Cooling Water Supply Motor Valves to the Auxiliary Feedwater Pumps
WO 0503890; Rewire MV-32030 to Resolve Appendix R Hot Short Issue

D5 Fuel Oil Pump Replacement

SP 2093; D5 Diesel Generator Monthly Slow Start Test; Revision 76
WO 0406239; Seal Leak on D5 Engine 2 Fuel Oil Pump
WO 0503898; Replace Recirc Air Damper MD-32422

1R22 Surveillance Testing

SP 2353A

SP 2353A; Quarterly Testing of CS-47 and CS-49, 21 Containment Spray Pump Suction and Discharge Check Valves; Revision 6
CAP 043506; 21 Containment Spray Pump Discharge Check Valve Failed SP 2353A
10 CFR 50.59 Screening 2450; Revision of Surveillance Procedure SP 2353A; Revision 0
Procedure H10.1; American Society of Mechanical Engineers Inservice Testing Program

SP 1102

SP 1102, 11 Turbine-Driven Auxiliary Feedwater Pump Monthly Test; Revision 83
CAP 044285; Incorrect Note in SP 1102 Conflicts With Step

SP 1780

SP 1780; AMSAC Quarterly Functional Test; Revision 8
CAP 043978; AMSAC Reset Timer Display Shows Incorrect Time on MMI

SP 1106A

SP 1106A; 12 Diesel-Driven Cooling Water Pump Monthly

SP 2155B

SP 2155B; Component Cooling System Test Train B Quarterly

1R23 Temporary Modification 05T193

Listing of Installed Temporary Modifications as of September 1, 2005
Temporary Modification Control Form 05T193
Standard 10 CFR 50.59 Screening 2427; Temporary Modification 05T193; Revision 0
CAP 043810; Survey Results in Unit 2 Containment Show Elevated Radiation Levels on 755 Foot Elevation

1EP2 ANS Testing

SP 1397; Emergency Plan Fixed Siren Test; dated May 20 , 2005
PINGP 1120; Monthly Trend Report; dated June 2003 through May 2005
PINGP 1479; Siren Maintenance Checklist; dated October 2003 through October 2004
Section Work Instruction EP-630; Annual Fixed Siren Maintenance; Revision 0
Sirens Form 3; Monthly Failure Matrix; dated June 2003 through May 2005
Monthly Siren History Spread Sheet; dated June 2003 through May 2005
Monthly Causes of Siren Failures; dated June 2003 through May 2005

1EP3 ERO Augmentation Testing

PINGP Emergency Plan, Table 1; Guidance for Augmentation of Plant Emergency Organization; Revision 32
PINGP 579; Emergency Notification Call List for a Notification of Unusual Event; Revision 113
PINGP 580; Emergency Notification Call List for an Alert, Site Area Emergency, or General Emergency; Revision 121
SP 1744; Semi-Annual Emergency Organization Augmentation Response Test; Revision 31
Training Program Description P7400; Emergency Plan Training; Revision 16
PINGP Site ERO Roster Second Quarter 2005; dated April 19, 2005
ACE 008987; Failure of ERO B-1 Table Staffing During Augmentation Test; dated June 24, 2005
ACE 008932; ERO Augmentation Response Test Conducted on March 15, 2005 Was Not Completed Satisfactorily; dated March 17, 2005

CAP 043281; Semi-Annual Emergency Organization Augmentation Response Test Staffing Criteria Does Not Meet Prairie Island Emergency Plan Requirements; dated June 30, 2005
CAP 043246; Long Range Pagers Did Not Actuate; dated June 27, 2005
CAP 043219; Failure of ERO B-1 Table Staffing During Augmentation Test; dated June 24, 2005
CAP 043214; ERO Callout Pager Message Problem; dated June 24, 2005
CAP 041409; ERO Augmentation Response Test Conducted on March 15, 2005, Was Not Completed Satisfactorily; dated March 17, 2005

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

PINGP Emergency Preparedness Readiness Assessment; dated April 5, 2005
PINGP February 9, 2005, Emergency Plan Drill Critique Report; dated May 2, 2005
PINGP June 14, 2004, Exercise Critique Report; dated June 23, 2004
Nuclear Oversight Observation Report 2005-001-6-020; Fleet Integrated EP Assessment - State and Local Interface; dated April 20, 2005
Nuclear Oversight Observation Report 2005-001-6-012; Observation of February 9, 2005, Emergency Plan Drill; dated March 31, 2005
Nuclear Oversight Observation Report 2004-001-6-022; 10 CFR 50.54(t) Assessment of the Prairie Island Emergency Preparedness Program; dated March 15, 2004
QF-0408; Internal Operating Experience Rapid Notification Report; dated June 9, 2005
ACE 008819; Emergency Plan Emergency Action Levels (EALs) and F3-2 Classifications of Emergencies Were Inappropriately Revised; dated January 20, 2005
CAP 043295; Re-evaluation of Augmentation Drills Reveals Additional Failures in the Last Two Years; dated June 30, 2005
CAP 043009; Shift Manager Only Faxes Emergency Notification Form If There Are No Shift Emergency Communicators; dated June 9, 2005
CAP 043008; Emergency Response Organization Offsite Mustering; dated June 9, 2005
CAP 035326; Revise Emergency Plan EALs and F3-2 Classifications of Emergencies to Reflect the Corrected EALs; dated February 12, 2004
OE 035582; NRC RIS 2004-15, Emergency Preparedness Issues; dated November 1, 2004

1EP6 Drill Evaluation

PINGP August 2005 EP Drill Critique Report
CAP 043795; Field Teams Not Dispatched During 8/3/05 E-Plan Drill
CAP 043796; Untimely Follow-up Message During 8/3/05 E-Plan Drill
CAP 043798; Radiation Control Not Established at Assembly Point During 8/3/05 E-Plan Drill
CE 008634; Field Teams not Dispatched During 8/3/05 E-Plan Drill
CA 011806; Field Teams not Dispatched During 8/3/05 E-Plan Drill
CA 011807; Field Teams not Dispatched During 8/3/05 E-Plan Drill
CA 011808; Field Teams not Dispatched During 8/3/05 E-Plan Drill

2OS1 Access Control to Radiologically Significant Areas

CAP 042711; Two Operators Working In the Overhead Without Notifying Radiation Protection; dated May 25, 2005
CAP 042415; 2R23 Worker Received Valid Dose Alarm; dated May 15, 2005
CAP 042671; Worker Did Primary Steam Generator Channel Head Half Jump Instead of Reach-in Entry; dated May 24, 2005
CAP 042941; Tools from Prairie Island Identified at Callaway During Steam Generator Team Tool Shake Out; dated June 6, 2005
CAP 043198; Radioactive Material Labeling and Documentation Not in Accordance With Site Procedures; dated June 23, 2005
CAP 043115; Elevator Usage Not Controlled During Transfer of Filters; dated June 16, 2005
CAP 043522; Operation and Chemistry Sampling Differences for Radiological Systems; dated July 21, 2005
CAP 043810; Survey Results in Unit 2 Containment Show Elevated Radiation Levels on 755; dated August 4, 2005
CAP 043816; Radiation Protection Implementing Procedure Administrative Issues; dated August 4, 2005

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

CAP 031131; Fire Brigade Equipment Missing; dated June 30, 2003
CAP 031726; Available Emergency Breathing Air Supply Does Not Appear to Meet H28 Requirement; dated August 5, 2003
CAP 041532; Spent Fuel Pool Radiation Monitor R-25 Reading Erratically; dated March 27, 2005
CAP 042833; SP 1664 Fire Fighting Equipment Check Completed Unsatisfactory; dated May 31, 2005
CAP 043816; Radiation Protection Implementing Procedure Administrative Issues; dated August 4, 2005
Other (OTH) 039277; Radiation Protection-Chemistry Department Roll-up Meeting Report, Second Quarter 2005; dated July 27, 2005
PINGP 683; Calibration Data Sheet National Nuclear Corporation Friskall; Revision 8
PINGP 705; Meter Calibration Data Sheet Frisker Model RM-14; Revision 8
PINGP 748; Meter Calibration Data Sheet Extender Model 2000W; Revision 6
PINGP 1028; Respiratory Protection Checks; Revision 12
PINGP 1149; Meter Calibration Data Sheet RO-20 Ion Chamber; Revision 1
Radiation Protection Implementing Procedure (RPIP) 1215; Respiratory Equipment Control; Revision 4
RPIP 1224; Calibration and Manager Menu Operations for the FastScan Whole Body Counter; Revision 4
RPIP 1310; Radioactive Waste Streams Scaling Factors; Revision 7
SP 1783.1; Westinghouse Radiation Monitor Electronic Calibration; Revision 6
SP 1783.2; Nuclear Measurement Corporation Radiation Monitor Electron Calibration; Revision 7
SP 1783.4; High Range Radiation Monitor Electronic Calibration; Revision 4

QF-0406 (FP-PA-SA-03), Radiation Protection Portable Instrumentation and SCBA Snap Shot Self-Assessment Report; dated April 4, 2005
Part 61 Waste Stream Report; dated April 2, 2001
Part 61 Waste Stream Report; dated September 12, 2004
MSA Procheck 3 Test Results; Complete SCBA Test; dated April 19, 2005
MSA Procheck 3 Test Results; Complete SCBA Test; dated May 23, 2005
FastScan Whole Body Calibration; dated June 23, 2005

4OA1 Performance Indicator Verification (71151)

ANS Reliability

H33.4; Emergency Preparedness Performance Indicators Reporting Instructions; dated June 15, 2005
Records of Monthly ANS Test Results; dated April 2004 through March 2005
CAP 038207; Goodhue Sirens Failed to Activate on First Attempt; dated September 1, 2004

ERO Participation

PINGP NRC Emergency Plan Participation Performance Indicator Data for Monthly Report; dated April 2004 through March 2005
Monthly PINGP Site ERO Roster; dated March 31, 2005
Monthly Emergency Preparedness Key ERO Record; dated March 31, 2005, January 7, 2005, July 13, 2004, and June 11, 2004
Monthly NMC Attendance and Emergency Preparedness Codes; dated April 2004 through March 2005

Drill and Exercise Performance

Drill and Exercise Performance Data for Monthly Report; dated April 2004 through March 2005
PINGP February 9, 2005, EP Drill Critique Report

4OA2 Identification and Resolution of Problems

Annual Sample - Non-Code Repairs to Unit 2 Containment Fan Coil Units

RCE 000196; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CAP 041535; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CAP 042044; Additional Corrective Actions Related to RCE 000196
CA 010689; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CA010690; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CA 010691; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CA 010695; Additional Corrective Action to RCE 000196
CA 010696; Additional Corrective Action to RCE 000196
CA 010697; Additional Corrective Action to RCE 000196
CA 010698; Additional Corrective Action to RCE 000196

CA 010699; Additional Corrective Action to RCE 000196
CA 010900; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
CA 010901; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
Effectiveness Review (EFR) 10692; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
EFR 010693; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
EFR 010694; Non-Code Repair of Containment Fan Coil Units Tubing and Fittings
EFR 011557; Additional Corrective Action to RCE 000196

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
AMSAC	ATWS Mitigating System Actuation Circuit
ANS	Alert and Notification System
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
CA	Corrective Action
CAP	Corrective Action Program Action Request
CC	Component Cooling Water
CE	Condition Evaluation
CFCU	Containment Fan Coil Unit
CFR	Code of Federal Regulations
CL	Cooling Water
EAL	Emergency Action Levels
EFR	Effectiveness Review
EP	Emergency Preparedness
ERO	Emergency Response Organization
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IR	Inspection Report
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MIC	Micro-biologically Induced Corrosion
MRE	Maintenance Rule Evaluation
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NMC	Nuclear Management Corporation, LLC
NRC	U.S. Nuclear Regulatory Commission
OE	Operating Experience
OPR	Operability Recommendation
OTH	Other
OWA	Operator Workaround
PARS	Publicly Available Records
PINGP	Prairie Island Nuclear Generating Plant
PRA	Probabilistic Risk Assessment
psi	Pounds Per Square Inch
psid	Pounds Per Square Inch Differential
RCE	Root Cause Evaluation
RHR	Residual Heat Removal
RPIP	Radiation Protection Implementing Procedure
RT	Radiography
SCBA	Self-Contained Breathing Apparatus
SDP	Significance Determination Process
SP	Surveillance Procedure
TP	Test Procedure
TS	Technical Specifications

UHS	Ultimate Heat Sink
UT	Ultrasonic Examination
USAR	Updated Safety Analysis Report
WO	Work Orders