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

September 20, 2012

Mr. Joel P. Sorensen
Acting Site Vice President
Prairie Island Nuclear Generating Plant
Northern States Power Company, Minnesota
1717 Wakonade Drive East
Welch, MN 55089

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2; NRC INSPECTION REPORT 05000282/2012011; 05000306/2012011 FOLLOWUP OF UNIT 1 NOTICE OF UNUSUAL EVENT DUE TO REACTOR COOLANT SYSTEM LEAKAGE GREATER THAN 10 GALLONS PER MINUTE

Dear Mr. Sorensen:

On September 14, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Prairie Island Nuclear Generating Plant, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on September 14, 2012, with you and other members of your staff.

This report documents the circumstances behind the March 6, 2012, declaration of a Notice of Unusual Event (NOUE) on Unit 2, due to RCS leakage exceeding 10 gallons per minute. The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Three NRC-identified findings of very low safety significance (Green) were identified during this inspection. Two of these findings were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant. If you disagree with the cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Prairie Island Nuclear Generating Plant.

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

Sincerely,

***/RA/***

Kenneth Riemer, Branch Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2012011; 05000306/2012011
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket Nos: | 50-282; 50-306; 72-010 |
| License Nos: | DPR-42; DPR-60; SNM-2506 |
| Report Nos: | 05000282/2012011; 05000306/2012011 |
| Licensee: | Northern States Power Company, Minnesota |
| Facility: | Prairie Island Nuclear Generating Plant, Units 1 and 2 |
| Location: | Welch, MN |
| Dates: | March 12-16, 2012 (on-site inspection)<br>September 13-14, 2012 (in office review) |
| Inspectors: | N. Shah, Project Engineer<br>C. Moore, Operator Licensing Examiner |
| Approved by: | K. Riemer, Chief<br>Branch 2<br>Division of Reactor Projects |

Enclosure

# TABLE OF CONTENTS

## SUMMARY OF FINDINGS

IR 05000282/2012011; 05000306/2012011; March 12-16, 2012; Prairie Island Nuclear Generating Plant, Units 1 and 2; Other Activities.

This report covers circumstances behind the March 6, 2012, declaration of a Notice of Unusual Event (NOUE) on Unit 2, due to RCS leakage exceeding 10 gallons per minute. The inspectors identified three findings, two with associated non-cited violations, all having a significance of Green, for Unit 2. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

### A. NRC-Identified and Self-Revealed Findings

**Cornerstone: Mitigating Systems**

- Green. An inspector-identified finding of very low safety significance was identified due to the failure to take corrective action for a Condition Adverse to Quality. The inspectors determined that the failure to correct for the loss of reactor coolant system (RCS) level indication during the 2010 refueling outage was a performance deficiency that required an evaluation using the SDP. This deficiency was more than minor as the loss of RCS level indication during draining, may result in level decreasing to the point where the function of the safety-related residual heat removal system may be affected. These level indication issues recurred during the RCS draining on March 6, 2012, resulting in a Notice of Unusual Event (NOUE) being declared. The licensee initiated Action Request (AR) 1329470 to evaluate this issue.

  This finding was determined to be crosscutting in the Problem Identification and Resolution, area because the licensee had not taken appropriate corrective actions to address the RCS level indication issues (P.1 (d)). This finding was not considered a violation, as the affected RCS level indicators were not considered safety-related. (Section 4OA2)

- Green. An inspector-identified finding of very low safety significance and a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, was identified due to the licensee's use of an inadequate procedure during draining of the RCS. The inspectors determined that the procedure used during the March 6, 2012, draining of the reactor coolant to the vessel flange level, did not contain adequate guidance for identifying and compensating for inadequate reactor vessel level indication due to over pressurization of the reactor vessel. This was a performance deficiency that required an evaluation using the SDP. This deficiency was more than minor as inaccurate RCS level indication resulted in plant operators declaring an NOUE and overdraining the RCS to the point where the function of the safety-related residual heat removal system was potentially affected. The licensee initiated Action Request (AR) 1329465 to evaluate this issue.

  This finding was determined to be crosscutting in the Resources area, because the licensee has not maintained compete, up-to-date procedures for performing RCS draining (H.2(c)). The licensee had prior instances where RCS level indication was lost due to vessel overpressure; however, the licensee decided not to revise the procedures based on an incorrect assumption that the procedures contained adequate guidance. (Section 4OA5).

- Green. An inspector-identified finding of very low safety significance and an NCV of 10 CFR 50, Appendix B, Criterion III, was identified due to the licensee's failure to update engineering calculations for the amount of nitrogen to be used during steam generator tube draining. Specifically, the failure to correctly include the number of plugged steam generator tubes into the engineering calculations was considered a performance deficiency. This deficiency was more than minor, as it contributed to the vessel overpressure that resulted in overdraining of the RCS on March 6 2012, and a NOUE. The licensee initiated ARs 01328420, 01329464, and 01328366 to evaluate this issue.

  This finding was determined to be cross-cutting in the area of Resources, specifically having complete and up-to-date design documentation (H.2.(c)). Because the licensee inappropriately placed the engineering calculations in "non-active" status, they were not updated to reflect the actual number of plugged steam generator tubes. This resulted in the station procedure incorrectly stating the amount of nitrogen needed and the amount of water removed during steam generator tube draining. (Section 4OA5).

**B. Licensee-Identified Violations**

No violations of significance were identified.

## REPORT DETAILS

# 1. REACTOR SAFETY

### Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

Event Description

On March 6, 2012, at about 4:30 a.m., the licensee began lowering Unit 2 reactor water level to 1 foot below the vessel flange. The draining was performed in accordance with station procedure, 2C4.1, “RCS Inventory Control—Pre-Refueling,” Revision 29. Because this occurred coincident with the draining of the steam generator tubes, the licensee used Sections 5.1 and 5.2 of the procedure. Prior to the drain down, Unit 2 was shutdown and in mode 5 as part of a planned refueling outage.

During the draining, there were no observed problems with RCS level instrumentation. The licensee relied on two narrow range RCS level indicators and a wide range refueling canal level indicator for normal RCS monitoring. One ultrasonic monitor was also available to monitor water level in the hot leg piping. Additionally, the reactor vessel level instrumentation system (RVLIS) system was available, but was used for trending only.

At about 6:08 a.m., Westinghouse contract staff began to remove the reactor vessel head vent spool piece. This work was part of the preparatory activities for the later removal of the reactor vessel head. At about 6:24 a.m., the license received indications of a potential loss of RCS inventory exceeding 10 gallons per minute. Subsequently, the licensee declared a NOUE.

The operators started 2 of 3 charging pumps and were able to stabilize RCS level. After about 2400 gallons of water was injected, the operators stopped the charging pumps and observed that RCS level remained stable at 1 foot below the vessel flange. Based on the amount of water added, the licensee believes that the normal RCS level instrumentation was inaccurate and that the licensee had actually lowered water level to about 3-12 inches above the reactor water hot legs (or about 46 inches below the original target level). Had the draining continued for another 17 inches; the RCS level would have declined to the mid-loop level, potentially affecting the function of the safety-related residual heat removal system.

The licensee believed that the reactor vessel was over pressurized; causing a loss of RCS level indication. As stated in Section 4OA2, a similar issue occurred during the April 2010 refueling outage. When the reactor vessel vent spool piece was removed, the excess pressure was vented, and the RCS level indication returned to normal. Since the licensee had drained the vessel to a level lower than indicated, the indicated level dropped to reflect the actual level, which the operators mistook as an actual decline in water level. The licensee documented this issue in the Corrective Action Program as AR 1327920 and conducted a Root Cause Evaluation.

The root cause evaluation identified that a potential sloping issue with the Unit 2 reactor coolant gas vent system (RCGVS) piping likely resulted in partial blocking of this piping preventing proper pressure relief from the reactor vessel head. As part of the corrective action for this event, the Unit 2 RCGVS piping was modified prior to the Unit 2 restart.

Unit 2 returned to full power operation on June 11. 2012.

1R18 Plant Modifications (71111.18)

.1 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- Engineering Change (EC) 19795 – Unit 2 Reactor Head Vent Improvement Modification

The inspectors reviewed the configuration change and associated 10 CFR 50.59 safety evaluation/screening against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents; the modification operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modification did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

## 4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

**Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity**

.1 Selected Issue Follow-Up Inspection: Review of Licensee Follow-up Following Unexpected Drop in RCS Levels on April 23, 2010

a. Inspection Scope

The inspectors reviewed an Apparent Cause Evaluation associated with AR 01229074. This AR was written in response to three anomalies with indicated RCS level that occurred during the 2010 Unit 2 refueling outage. The licensee considered these anomalies as Conditions Adverse to Quality. As part of the evaluation, the licensee also reviewed prior events going back to 1992. The inspectors evaluated whether the licensee had appropriately identified the apparent causes and developed corrective actions as part of the aggregate review. However, the inspectors did not review the specific evaluations the licensee had previously performed for the individual events.

This review was performed as part of the inspectors' evaluation of the March 6, 2012, Unit 2 NOUE declaration discussed in Section 4OA5 of this report.

The issue was of concern because absent accurate level indication during draining, the RCS level may decrease sufficiently to potentially prevent the safety-related residual heat removal system from functioning.

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

This review constituted one in-depth problem identification and resolution sample as defined in IP 7115205.

b. Findings

(1) Failure to Implement Corrective Action to Address Problems with Indicated RCS Level

Introduction: An inspector-identified finding of very low safety significance (Green) was identified due to the failure to take corrective action for a Condition Adverse to Quality. Specifically, the licensee did not implement appropriate corrective action to address anomalies with RCS level indication during the 2010 Unit 2 refueling outage. These level indication issues recurred during the RCS draining on March 6, 2012, resulting in an NOUE being declared.

Discussion: On April 24, 2010, the licensee initiated AR 1229074 to address three anomalies with RCS level indication occurring during the 2010 Unit 2 refueling outage. These issues were considered precursors to the loss of RCS level indication that resulted in the March 6, 2012, NOUE.

During the 2010 outage, the licensee experienced three instances where RCS level indication was lost, due to vessel overpressure. The overpressure resulted from a combination of coolant offgas (i.e., release of fission product gases from the RCS) and nitrogen gas, used to drain the steam generator tubes, migrating into the reactor vessel.

The licensee relied on two narrow range RCS level indicators and a wide range refueling canal level indicator for level monitoring during draining. These indicators used the differential pressure between the reactor vessel and the primary containment to determine level. These indicators were uncompensated, meaning that an increase in reactor vessel pressure resulted in a higher than actual indicated level. The RVLIS was also available, but was used for trending only. The RVLIS system used the differential pressure between the top and bottom of the reactor vessel to determine level and was unaffected by vessel overpressure.

The licensee's determined that operators did not fully recognize when overpressure occurred and, therefore, did not always know when level instrumentation was suspect. The evaluation concluded that to address the loss of RCS level indication, ultrasonic monitors (which were unaffected by vessel overpressure) be installed. Otherwise, no other corrective action was recommended.

The inspectors concluded that the licensee evaluation was limited and that the stated corrective action would not prevent the loss of RCS level indication due to overpressure. Specifically, the inspectors noted:

- The evaluation did not address why the vessel overpressure occurred (i.e., was it due to inadequate venting of the vessel head, use of excess nitrogen during steam generator tube draining or another cause).

- The licensee concluded that station procedures had sufficient guidance for operators regarding vessel overpressure and that no additional corrective action was needed. However, the inspectors questioned this conclusion, as the licensee had not evaluated why this guidance had not prevented the 2010 anomalies. Additionally, as stated in Section 4OA5, the inspectors identified that the same operating procedure was used during the March 6, 2012, RCS draining and was inadequate.

- The licensee required that the ultrasonic monitors be installed on the RCS hot legs; meaning that the majority of the reactor vessel level would only be monitored by the normal RCS level indication.

The inspectors also identified a knowledge deficiency with respect to the RVLIS. Licensee staff (i.e., operations, maintenance, and engineering) believed that the system was unreliable and therefore, tended to discount disagreement between RVLIS and the normal RCS level instruments. The reason for this belief was unknown as RVLIS was well maintained, calibrated appropriately and had passed surveillance testing. Additionally, the inspectors noted that the operators were unfamiliar with the relationship between indicated RVLIS level and actual reactor vessel level. As stated in Section 4OA5, the operators had prior indication of the vessel overpressure during the NOUE, based on indicated RVLIS level. The licensee initiated AR 1329469 to evaluate this issue.

Analysis: The inspectors determined that the failure to correct for the loss of RCS level indication during the 2010 refueling outage was a performance deficiency that required an evaluation using the SDP. This deficiency was more than minor as the loss of RCS level indication during draining, may result in level decreasing to the point where the function of the safety-related residual heat removal system may be affected. As stated in Section 4OA5, inaccurate RCS level indication due to vessel overpressure was a primary cause of the March 6, 2012, NOUE.

Since the plant was shutdown in Mode 5, the Senior Reactor Analysts (SRAs) conducted an assessment of the risk significance of the event in accordance with IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process.” Table 1 of Appendix G, "Losses of Control," states that a loss of level control in PWRs occurs when there is an inadvertent loss of 2-feet of RCS inventory when not in midloop. Since this condition in Table 1 was met, Appendix G states that the finding needs to be quantitatively assessed via the Phase 2 or 3 processes.

The SRAs reviewed Appendix G, Attachment 1, “Phase 1 Operational Checklists for Both PWRS and BWRS. The applicable checklist was Checklist 3, “PWR Cold Shutdown and Refueling Operation RCS Open and Refueling Cavity Level < 23' OR RCS Closed and No Inventory in Pressurizer Time to Boiling < 2 hours.” The applicable line items were:

- II.A. (2) – discusses two sources of continuous level indication being monitored by operators; and
- II.B. (5) – discusses drain down being controlled; inventory balances performed and appropriate action taken on level deviation.

Therefore, Phase 1 criteria were met and the risk evaluation progressed to Phase 2. The SRAs reviewed Appendix G, Attachment 2, "Phase 2 Significance Determination Process Template for PWR during Shutdown." In Phase 2, The Plant Operating State was POS-2 (reduced inventory operations) with an early time window. The exposure time is the period when the discrepancy existed between indicated level and actual level. This was determined to be 9-days, from February 27 to March 6, 2012. February 27 is the date when the RCS was depressurized, the RCPs were stopped, and RVLIS started to trend down indicating gas starting to collect in the reactor vessel head due to an inadequate reactor head vent. On March 6, the RCS overpressure was relieved by removal of the reactor vessel head vent spool piece and indicated level dropped to actual level. The SRA evaluated the impact of the performance deficiency on all of the initiating events ("initiators") in Appendix G.

Loss of Level Control

The Loss of Level Control (LOLC) initiator involves the potential for operators to over-drain the RCS on March 6 such that the RHR function is lost. The LOLC frequency is effectively the probability of operators over-draining the RCS while in midloop. Although the plant did not reach midloop conditions, the guidance in Appendix G was an appropriate tool for evaluating the risk. The LOLC initiator was evaluated as a "precursor" event per Appendix G. During the event operators believed they had drained to 1-foot below the reactor vessel flange, but actually had drained to as low as 3 inches above the top of the RCS hot legs. The SGs were not available for RCS cooling.

Based on review of the licensee's investigation, the lowest level the reactor could physically reach was about 1.3-inches below hot leg centerline using the drain configuration specified in Section 5.2.6 of Procedure 2C4.1, "RCS Inventory Control – Pre-Refueling." At a level of 1.3-inches below the hot leg centerline, a flow through the RHR suction nozzle of greater than approximately 1500 gpm is needed to cavitate the running pumps per WCAP-11916, "Loss of RHR Cooling While the RCS is Partially Filled," Rev. 0. The actual flow rate at the time was about 1100 gpm. In addition to the WCAP, the SRAs evaluated the potential for air entrainment and vortexing at the suction of the RHR pumps against guidance from NRC Temporary Instruction (TI) 2515/177, Revision 1, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (NRC Generic Letter 2008-001)." The SRAs agreed that during the March 6 event the RHR function would not have been lost.

The SRA concluded that the risk impact of the performance deficiency on the LOLC initiator was not applicable.

Loss of Inventory

Faulty level indication could impact plant response to loss of inventory events. Appendix G states that many of these flow diversions are caused from improper alignment of valves. The Loss of Inventory (LOI) initiator was representative of a "condition" event as defined in Appendix G Attachment 2. The condition is the time-based condition of having faulty level indication during the exposure period. For the initiating event frequency, the SRAs used Table 5 - Initiating Event Likelihood (IELs) for Condition Findings – PWRs." The exposure time for the degraded condition was 3-30 days. The IEL listed for 3-30 days exposure time is 1E-3.

The mitigating functions for this initiator were evaluated using Worksheet 6, "SDP for a PWR Plant - Loss of Inventory in POS 2 (RCS Vented)." In Worksheet 6, the dominant sequence involved operators injecting water (i.e., "FEED") to the RCS given a random loss of RCS inventory event. FEED is a common recovery procedure for an extended loss of RHR and is performed similar to the full power procedures.

Appendix G Attachment 2 states that the lower of equipment and operator credits be used to determine the credit for the mitigating function. The SRA used the operator credit since it was lower than equipment credit. Multiple RCS makeup flow paths were available for the equipment credit, including two charging pumps with suction for one pump from the volume control tank and the other pump from the refueling water storage tank; an RHR pump with suction from the refueling water storage tank; and a safety injection pump with suction from the refueling water storage tank.

The basis document for Appendix G, "IMC 0308, Attachment 3, 'Technical Basis,'" had the default value for FEED (operator credit) of 1E-4 based on the Standard Plant Analysis Risk Human Reliability Method (SPAR-H) low power and shutdown sheets. Core damage is assumed to occur after 3-hours without FEED. The SRAs determined this to be a valid assumption for Prairie Island since for the March 6 event the amount of time required to boil off enough water to lower RCS level from the top of the hot legs to the top of active fuel was about 3 hours from the time that saturation conditions were reached in the RCS.

For the default case, the Performance Shaping Factor (PSF) for time was expansive with the remaining PSFs being nominal. For this specific case at Prairie Island, stress was considered an additional performance driver due to the discrepant level indication. The SRA increased the default operator credit from 1E-4 to 2E-4 using the SPAR-H low power and shutdown worksheets assuming high stress in addition to expansive time. The other performance shaping factors were left at their nominal values. The SRA assigned the value of 2E-4 for FEED.

Appendix G, Attachment 2 states that if referenced instrumentation is misleading, then decrease the operator credit by two orders of magnitude based in part on poor ergonomics. The SRAs considered decreasing the operator credit by two orders to be overly-conservative. The key reason was that operators would have had accurate level instrumentation available well before core damage. The system overpressure causing the level error would be relieved when RCS level decreased below the top of the cold leg. Also, while the specific level value was inaccurate above the height of the cold leg, the system was still capable of displaying level trend thus providing a cue to operators of a possible LOI event. Loss of inventory would have caused containment sump levels to rise which was also an available cue for lowering reactor level. For the March 6 event the plant had core exit thermocouples available as a cue for rising RCS temperature. Finally, the plant had alternate RCS level indication accurate below the top of the RCS hot leg via an ultrasonic level channel which was unaffected by the $N_2$ overpressure effects. For these reasons the SRAs did not consider the ergonomic PSF to be a performance driver.

The remaining two sequences involved stopping the loss of inventory before RWST depletion, and restarting a failed RHR pump before RWST depletion. A note applicable to these sequences states that if there is "sufficient RWST inventory to last 24-hours, then this event is considered to be always successful." The quantity of water in the RWST was sufficient for 24-hours assuming a reasonable loss of inventory flow rate of 100 gpm. Since the RWST had sufficient inventory these sequences screen out.

The result for the LOI initiator was 2E-7.

Loss of RHR

The Loss of RHR (LORHR) initiator was also considered a condition event. The potential for losing RHR during the actual draindown event is captured in the LOLC precursor evaluation (i.e., N/A). The LORHR initiator is evaluated further because there is some potential for losing RHR under circumstances different than the actual event, and operator response is hampered by the existing inaccurate level indication.

For the LORHR initiating event frequency, the SRAs used Table 5 - Initiating Event Likelihood (IELs) for Condition Findings – PWRs." As discussed above, the exposure time for the degraded condition was 3-30 days. The IEL listed for 3-30 days exposure time is 1E-2.

The mitigating functions for this initiator were evaluated using Worksheet 9, “SDP for a Westinghouse 4-Loop Plant - Loss of RHR in POS 2 (RCS Vented).”

In Worksheet 9, only the sequence involving the need for level indication was solved since this reflected a change from the base case. This sequence involved the mitigating functions of RHR recovery before RCS boiling (i.e., "RHR-S") in addition to the function of "FEED" as discussed in the LOI initiator above. For the RHR-S function, a credit of 1E-3 was assigned since time to boil was greater than 1 hour. A credit of 2E-4 was assigned to the FEED function as for the LOI initiator.

The result for the LORHR initiator was 2E-9, and is insignificant relative to the LOI result.

Loss of Offsite Power

These sequences involve SBO events. The frequency of a SBO is very low compared to the other initiators and subsequent RHR and feed failures do not contribute to the overall significance of the finding.

The result for the Loss of Offsite Power initiator is insignificant relative to the LOI result.

Results of Internal Event Analysis

The total risk result of the internal event analysis is the sum of the individual results from the initiators above adjusted by the counting rule (i.e., multiply by 3.3) that is described in IMC 0609, Appendix A. The total internal event risk is on the order of 6.6E-7.

Large Early Release Frequency

Since the total estimated change in core damage frequency was greater than 1.0E-7/yr, the potential risk contribution for this finding from large early release frequency (LERF) was screened using the guidance of IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." For the evaluation of risk significance during shutdown, only the period within eight days of the beginning of the outage is considered. After eight days, it is assumed that the short-lived, volatile isotopes that are principally responsible for early health effects have decayed sufficiently such that the finding would not contribute to LERF. Since the event occurred greater than eight days from the beginning of the outage, there was no LERF contribution.

Considering the above information, the SRA determined the risk to be 6.6E-7, making this a finding of very low significance (Green).

This finding was determined to be crosscutting in the Problem Identification and Resolution, CAP area because the licensee has not taken appropriate corrective actions to address the RCS level indication issues as stated above (P.1 (d)). The licensee initiated AR 1329470 to evaluate this finding. **(FIN 05000282/2012002-01; Failure to Take Corrective Action for RCS Level Indication Issues).**

This issue was not a violation of NRC requirements as the aforementioned RCS level indicators were not considered safety-related.

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

.1 NOUE During Draining of RCS on March 6, 2012

a. Inspection Scope

The inspectors reviewed the licensee’s March 6, 2012, NOUE declaration as discussed in NRC Event Notice 47720. This event was also discussed as Unresolved Item (URI) 05000306/2012002-09.

The inspectors reviewed the operator logs, applicable operating procedures and other pertinent licensee documents as part of their evaluation of the event. The inspectors also interviewed selected licensee engineering, maintenance, emergency preparedness and operations staff to develop a timeline of the event and validate the licensee response. This review was conducted concurrent with the licensee’s Root Cause Evaluation.

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

This review constitutes one sample of IP 71153, “Event Response.”

b. Findings

.1 Inadequate Procedure Used During RCS Draindown

Introduction: An inspector-identified finding of very low safety significance (Green) and an NCV of 10 CFR 50, Appendix B, Criterion V, were identified due to the licensee’s failure to have a procedure appropriate to the circumstance during draining of the RCS.

Specifically, the procedure used during the March 6, 2012, draining of the reactor coolant to the vessel flange level, did not contain adequate guidance for identifying and compensating for inadequate reactor vessel level indication due to over pressurization of the reactor vessel.

Discussion: Station procedure 2C4.1 was divided up into several independent sections depending on the desired drain down level and if the draining was occurring coincident with steam generator tube draining. As stated, the licensee was using Section 5.1, "Preparation for Draining the RCS," and 5.2, "Drain the RCS to One Foot Below the Reactor Vessel Flange including Steam Generator Tube Draining," during this evolution. These sections cover the stated drain down and reflooding of the refueling pool to normal refueling level. It did not cover reduced inventory operations (defined as 3 feet below the vessel flange).

The procedure was considered an infrequently performed test or evolution that required a pre-job briefing prior to use. Attachment A to the procedure contained notes for the briefing. This Attachment was intended as a guide and not as a list of required actions. Regarding vessel overpressure and RCS indication, the Attachment stated the following:

- Excess nitrogen injection into the steam generators may result in RCS overpressure which can introduce a non-conservative error in the RCS level transmitters that could lead to over draining;

- The amount of nitrogen added to the generators has been calculated to cause "channeling" (i.e., steam generator tubes empty) by the time the RCS level reaches the flange. The operator should monitor the ultrasonic level indicators for evidence of channeling as RCS level approaches the flange.

- RVLIS was required to be in operation during the drain down, as previous experience had shown it to be a valuable tool in identifying the potential for vessel overpressure.

The Attachment also discussed the normal RCS level instrumentation and reiterated that they were subject to inaccuracy if the RCS was improperly vented. The inspectors noted that these issues had been discussed with licensee staff during a briefing conducted prior to the RCS drain down.

The inspectors noted the following discrepancies with procedure 2C4.1:

- Step 4.1 stated that the ultrasonic indicators were not required for the RCS drain down. However, the procedure did not state how to monitor for "channeling" if the ultrasonic indicators were not used. For example, a CAUTION statement on page 29 of the procedure required that Step 5.2.6.J be performed if channeling was observed. This step reduced the drain down rate to ensure that accurate RCS level indication was available.

- Page 11 of the procedure contained a note stating that Figure C1-40, "Refueling Water Levels," may be used to correlate the various level indicators. The inspectors noted that this Figure did not address RVLIS indications. Based on discussion with plant operators, there was no clear correlation between the RVLIS indication and either the other RCS level instruments or the actual vessel level.

- Step 5.1.16 required that operators compare the normal RCS level indications to identify any discrepancies prior to starting draining. Subsequent CAUTION statements in the procedure (pages 19, 29, 33) reiterated comparing the normal RCS level instruments during drain down to monitor for discrepancies. However, if the vessel was overpressurized, then both RCS level instruments would respond consistently, but inaccurately. Therefore, this comparison would not identify whether RCS level indication was compromised.

Based on the above, the inspectors concluded that the procedure provided insufficient guidance for the operators to identify whether the RCS level indications were affected by vessel overpressure.

During a review of operator logs, the inspectors noted that at 1:10 a.m. on March 6, licensee operators had noted an apparent discrepancy between the RVLIS indication and the normal RCS level indication. This issue was documented as CAP 1329103. Licensee staff (i.e., operations, maintenance, and engineering) evaluated the issue and elected to continue with the drain down. This decision was, in part, based on a licensee belief that RVLIS was unreliable (see Section 4OA2) and that the normal RCS level indication was accurate. This combined with the lack of clear guidance in the drain down procedure, resulted in an early, missed opportunity to identify the vessel overpressure.

Analysis: The inspectors determined that the procedure used during the March 6, 2012, draining of the reactor coolant to the vessel flange level, did not contain adequate guidance for identifying and compensating for inadequate reactor vessel level indication due to over pressurization of the reactor vessel. This was a performance deficiency that required an evaluation using the SDP. This deficiency was more than minor as inaccurate RCS level indication resulted in plant operators declaring an NOUE and overdraining the RCS to the point where the function of the safety-related residual heat removal system was potentially affected.

The risk significance of this issue was documented in Section 4OA2 of this report. As stated, the SRA determined the risk to be 6.6E-7, making this a finding of very low safety-significance (Green).

This finding was determined to be crosscutting in the Resources area, because the licensee has not maintained compete, up-to-date procedures for performing RCS draining (H.2(c)). As stated in Section 4OA2, the licensee had prior instances where RCS level indication was lost due to vessel overpressure. However, the licensee decided not to revise the procedures based on an incorrect assumption that the procedures contained adequate guidance.

Enforcement: Criterion V of 10 CFR 50, Appendix B, requires, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances.

Contrary to the above, the procedure used for draining the RCS on March 6, 2012, did not contain adequate guidance for plant operators to recognize when RCS level was affected by vessel overpressure. This resulted in overdraining of the RCS on March 6, 2012, causing an NOUE to be declared. Because this violation was of very low safety significance and it was entered into the corrective action program as AR 01329465, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2012002-02; Inadequate Procedure for Draining of Reactor Coolant System).**

.2 Failure to Update the Design Calculations For Steam Generator Draining

Introduction: An inspector-identified finding of very low safety significance (Green) and an NCV of 10 CFR 50, Appendix B, Criterion III, was identified due to the licensee's failure to update engineering calculations for the amount of nitrogen to be used during steam generator tube draining.

Discussion: The licensee injected nitrogen gas into the steam generator tubes to displace water during draining. Because of the potential for nitrogen gas to migrate into the vessel and increase pressure, station procedure 2C4.1 specified the amount of nitrogen to be added and the volume of water to be drained.

Attachment A, of procedure 2C4.1, stated the following regarding nitrogen addition:

- Excess nitrogen injection into the steam generators may result in RCS overpressure which can introduce a non-conservative error in the RCS level transmitters that could lead to over draining;
- The amount of nitrogen added to the generators has been calculated to cause "channeling" (i.e., steam generator tubes empty) by the time the RCS level reaches the flange. The operator should monitor the ultrasonic level indicators for evidence of channeling as RCS level approaches the flange.
- Nitrogen flow meters were installed to monitor the amount of nitrogen being added to the steam generators. The monitors have a built in time delay of 30 seconds, which was accounted for in the design calculation for the nitrogen addition. Therefore, the operators should only add the amount of nitrogen specified in the procedure and not try to anticipate the delay.

Step 5.2.3(M) and (J) of procedure 2C4.1 listed the following criteria for when to stop the steam generator tube draining:

- A total of 1250 standard cubic feet (scf) of nitrogen was added;
- Channeling was observed in one of the ultrasonic level instruments (if in service); or
- 7850 gallons of water had been drained from the generator.

The values for the amount of water drained and the amount of nitrogen added were obtained from engineering calculations ENG-ME-425, "Unit 2 Steam Generator Tube Volume," dated January 4, 2000, and ENG-ME-430, "Nitrogen Addition for RCS Draindown," dated April 6, 2000. According to the licensee, about 1260 and 1261 scf of nitrogen was added to each Unit 2 steam generator, respectively, on March 6; exceeding the value specified procedure 2C4.1.

The inspectors identified that both calculations had been placed in "non-active" status even though the operating procedures they supported remained active and not been updated since 2000. The calculations used 195 and 207 tubes plugged in each Unit 2 steam generator, respectively; as of 2010 (the last Unit 2 refueling outage) these numbers had increased to 321 and 290 tubes, respectively. The additional plugged tubes would have reduced the amount of nitrogen needed and the water volume removed.

The inspectors also noted that calculation ENG-ME-430 did not account for the time delay of the nitrogen flow meter, as has been stated in procedure 2C4.1. This meant that additional nitrogen would have been added in the 30 seconds after the operator had reached the target value due to the time delay. Further, the nitrogen flow meter was not considered a critical component, meaning that it had not been calibrated or otherwise tested to verify its accuracy and performance. Therefore, it was questionable whether the licensee could accurately control how much nitrogen was actually being injected.

Analysis: The failure to correctly include the number of plugged steam generator tubes into the engineering calculations was considered a performance deficiency. This performance deficiency was more than minor, as it contributed to the vessel overpressure that resulted in overdraining of the RCS on March 6 2012, resulting in an NOUE and challenging the safety-related function of the residual heat removal system.

The risk significance of this issue was documented in Section 4OA2 of this procedure. As stated, the SRA determined the risk to be 6.6E-7, making this a finding of very low safety-significance (Green).

This finding was determined to be cross-cutting in the area of Resources, specifically having complete and up-to-date design documentation (H.2.(c)). Because the licensee inappropriately placed the engineering calculations in “non-active” status, they were not updated to reflect the actual number of plugged steam generator tubes. This resulted in the station procedure incorrectly stating the amount of nitrogen needed and the amount of water removed during steam generator tube draining.

Enforcement: Criterion III of 10 CFR 50, Appendix B, requires, in part, that design basis are correctly translated into specifications, drawings, procedures and components.

Contrary to the above, the licensee did not properly maintain the supporting engineering calculations for the draining of the steam generators, as controlled by operating procedure 2C4.1. This resulted in the addition of excess nitrogen gas which was a contributing cause to the NOUE from the overdraining of the RCS on March 6, 2012. Because this violation was of very low safety significance and it was entered into the corrective action program as ARs 01328420, 01329464, and 01328366, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2012002-03; Failure to Update the Design Calculations For Steam Generator Draining.)**

4OA5 Other Activities

.1 (Closed) URI 05000306/2012002-09: Review of Root Cause Evaluation for March 6, 2012, Notice of Unusual Event

a. Inspection Scope

The inspectors reviewed the subject root cause as part of the event evaluation documented above. The licensee concluded that a gas bubble had formed in the reactor vessel on February 26, while pressurizer level was being lowered to 30%. The gas bubble was caused by the release of fission product gases from the reactor coolant into the vessel. Subsequently, the bubble increased as excess nitrogen escaped into the vessel during the draining of the steam generators. The gas bubble increased the pressure in the reactor vessel causing the reactor level instrumentation to read incorrectly.

In the Root Cause Report, the licensee stated that the primary causes of this event were the increased reactor pressure due to the accumulation of gases inside the reactor vessel and the design issues associated with the RCGVS. The main contributing causes identified by the licensee were inappropriate use of internal operating experience by the licensee staff regarding prior level transients; inappropriate guidance in station procedures regarding gas accumulation in the vessel and the affect on RCS level instrumentation; the failure to update the calculations for injecting nitrogen into the steam generators; and the failure to appropriately consider alternate RCS level instrumentation, unaffected by RCS pressure changes. These conclusions were similar to those reached by the inspectors during their independent review.

The licensee had put the reactor coolant gas vent system (RCGVS) in service prior to draining the RCS, in order to remove excess gases from the vessel. The licensee theorized that water had entered the vent piping forming a loop seal, which prevented the excess gases from escaping. During the March 6 event, it was noted that after the RCGVS spool piece was removed, the gas level in the reactor vessel dropped significantly and a noticeable amount of water drained out of the vent piping.

The licensee performed a visual inspection of the RCGVS piping. This inspection did not identify any evidence of blocking in the RCGVS, but did identify some sections of piping which were improperly sloped; these sections were subsequently repaired. The licensee performed an engineering evaluation based on the walkdown results, which concluded that the RCGVS function as designed.

The inspectors identified the following issues with the licensee’s overall evaluation of the event:

- Since the licensee concluded that the RCGVS functioned appropriately, the root cause of the event (i.e., the overpressure of the vessel) was indeterminate; and

- The licensee did not evaluate whether the design function of other systems besides the RCGVS were affected by vessel overpressure.

The inspectors were concerned whether the licensee’s corrective actions were appropriate to allow plant operators to recognize when the vessel was overpressurized, what systems were affected, what contingency actions to take and what additional monitoring actions were needed to identify the root cause. The licensee documented this issue as AR 1340285.

Subsequently, on August 22, 2012, the licensee revised both the Root Cause Evaluation and the engineering evaluation of the Unit 2 RCGVS piping to address the inspectors concerns. The inspectors reviewed both documents and identified no significant issues.

The inspectors concluded that this URI can be closed based on the results of this review. No new findings or violations were identified during the review of the root cause.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

- On March 16, 2012, the inspectors had an interim exit meeting with Mr. Davison and other licensee staff to present the inspection results. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

- On September 13, 2012, the inspectors had a final exit via telephone with Mr. Molden and other licensee staff to present the final inspection results. Specifically, the inspectors discussed the results of the review of the revised root cause report and engineering evaluation that was issued on August 22, 2012. The licensee acknowledged the issues presented and confirmed that none of the potential report input discussed was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

J. Anderson, Regulatory Affairs Manager
C. Childress, Assistant Maintenance Manager
K. Davison, Director Site Operations
P. Huffman, Site Engineering Director
B. Mackenzie, Supervisor Performance Assessment
R. Madjerich, Assistant Plant Manager
J. Molden, Site Vice President
K. Petersen, Business Support Manager

Nuclear Regulatory Commission

K. Riemer, Chief, Reactor Branch 2, Region III
K. Stoedter, Senior Resident Inspector
P. Zurawski, Resident Inspector

## LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000282/2012011-01 | FIN | Failure to take corrective action for reactor coolant system level indication issues (Section 4OA2) |
| 05000282/2012011-02 | NCV | Inadequate Procedure for Draining of Reactor Coolant System (Section 4OA5) |
| 05000282/2012011-03 | NCV | Failure to update the calculations for steam generator draining (Section 4OA5) |

Closed

| | | |
|---|---|---|
| 05000282/2012011-01 | FIN | Failure to take corrective action for reactor coolant system level indication issues (Section 4OA2) |
| 05000282/2012011-02 | NCV | Inadequate Procedure for Draining of Reactor Coolant System (Section 4OA5) |
| 05000282/2012011-03 | NCV | Failure to update the calculations for steam generator draining (Section 4OA5) |
| 05000282/2012002-09 | URI | Review of root cause evaluation for March 6, 2012 Notice of Unusual Event |

Discussed

None.

## LIST OF DOCUMENTS REVIEWED

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

### PLANT PROCEDURES

| Number | Description or Title | Date or Revision |
|---|---|---|
| 2C4.1 | RCS Inventory Control—Pre Refueling | Revision 29 |
| 2D3 | Unit 2 Reactor Vessel Head Removal | Revision 8 |
| FP-E-SE-02 | Component Classification | Revision 8 |
| FP-E-RTC-02 | Equipment Classification | Revision 7 |
| SP2264 | Reactor Vessel Level Instruments Calibration | Revision 23 |
| 2C4 | Reactor Coolant System | Revision 10 |
| 2C1.6 | Shutdown Operations – Unit 2 | Revision 24 |
| ICPM 2-392 | 21/22 RCS Narrow Range Level Instruments Calibration | Revision 14 |
| ICPM 2-461 | Placing the Unit 2 Ultra Sonic RCS Level System in Service | Revision 7 |
| C12.4 | VCT Gas Control | Revision 18 |
| 2ES-0.3A | Natural Circulation Cooldown with CRDM Fans | Revision 13 |
| 2ES-0.4 | Natural Circulation Cooldown with Steam Void in Vessel | Revision 9 |

### CORRECTIVE ACTION PROGRAM DOCUMENTS

| Number | Description or Title | Date or Revision |
|---|---|---|
| AR 1229074 | Significant Drop in RCS ERCS D/P Levels Noted | 4/24/2010 |
| AR 1328084 | Ultrasonic Level Monitoring System “A” Loop Failure | 3/09/2012 |
| AR 1329103 | Potential Missed Opportunity to Identify RCS Level Divergence | 3/13/2012 |
| AR 0056634 | ERTF 99-07, Overdrain of U1 RCS While Draining to the Top of the Hotlegs | 3/26/2002 |
| AR 1233072 | Undocumented Valve Discovered on Head Vent Drain Lines | 5/16/2010 |
| AR 1155764 | RCS ERCS DP Level Response to Intermediate Leg Samples | 10/16/2008 |
| AR 1328366 | SG Volume in 2C4.1 Does Not Reflect Current Tube Plugging | 3/8/2012 |
| AR 1326826 | Flow Meter Not Calibrated Since Installation | 2/27/2012 |
| AR 1327977 | PINGP 666 From 3/6/12 Contained Incorrect Event Date | 3/6/2012 |
| AR 1328028 | While Performing PINGP 577 Did Not Circle Callback Number | 3/9/2012 |
| AR 1328042 | Use of Siren Tests in Aftermath of an NUE | 3/9/2012 |

**CORRECTIVE ACTION PROGRAM DOCUMENTS**

| Number | Description or Title | Date or Revision |
|---|---|---|
| AR 1328538 | RCS Level Lowered During 21 RCP Backseat | 3/9/2012 |
| AR 1328000 | NUE: Health Department Callback Not Accepted | 3/6/2012 |
| AR 1328036 | NUE Caused SGR Project Impact | 3/6/2012 |
| AR 1328281 | Command and Control Issues During 3/6/12 NUE | 3/8/2012 |
| AR 1328010 | 3/6/12 NUE Declaration Event Report | 3/6/2012 |
| AR 1328039 | NUE-3/6/12 PINGP 666 Not Initialed for Termination | 3/6/2012 |
| AR 1327965 | Termination Criteria for NUE 3/6/12 | 3/6/2012 |
| AR 1328019 | When Dialing NRC Number for Fax on PINGP 666 Plant Page Come | 3/9/2012 |
| AR 1328041 | NUE-3/6/12 F3-2 Classification of Emergencies | 3/6/2012 |
| AR 1329195 | Component Criticality for FI-18249 in Incorrect | 3/14/2012 |
| AR 1328042 | Use of Siren Tests in Aftermath of an NUE | 3/9/2012 |
| AR 1328538 | RCS Level Lowered During 21 RCP Backseat | 3/9/2012 |
| AR 1328000 | NUE: Health Department Callback Not Accepted | 3/6/2012 |
| AR 1328281 | Command and Control Issues During 3/6/12 NUE | 3/8/2012 |
| AR 1328010 | 3/6/12 NUE Declaration Event Report | 3/6/2012 |
| AR 1328039 | NUE-3/6/12 PINGP 666 Not Initialed for Termination | 3/6/2012 |
| AR 1328019 | When Dialing NRC Number for Fax on PINGP 666 Plant Page Come | 3/9/2012 |
| AR 1327965 | Termination Criteria for NUE 3/6/12 | 3/6/2012 |
| AR 1328041 | NUE-3/6/12 F3-2 Classification of Emergencies | 3/6/2012 |
| AR 1329195 | Component Criticality for FI-18249 in Incorrect | 3/14/2012 |

**CONDITION REPORTS GENERATED DURING INSPECTION**

| Number | Description or Title | Date or Revision |
|---|---|---|
| AR 1329469 | NRC Observation: Organizational use of RVLIS | 4/19/2012 |
| AR 1329465 | Potential Finding: Operating Procedure Quality | 3/16/2012 |
| AR 1329470 | Potential Finding: Corrective Actions wrt Level Anomalies | 3/16/2012 |
| AR 1329464 | Potential Finding: Design Control | 3/20/2012 |
| AR 1340285 | EC 20069 RCGVS Eval Does Not Address all Operability/Function | 6/5/2012 |
| AR 1328420 | N2 Flow Meter Not Calibrated Since Installation | 3/8/2012 |
| AR 1328437 | Add RVLIS to Fig C1-40 | 3/8/2012 |
| AR 1151893 | Reliability Issue with RCS Ultra-Sonic Level Sys. | 9/24/2008 |

**MISCELLANEOUS**

| Number | Description or Title | Date or Revision |
|---|---|---|
| 3784 | A(1) Action/Performance Improvement Plant | Revision 0 |
| | NSPM CAP Screening Package | 9/16/2010 |
| | Performance Assessment Review Board Package | 9/14/2010 |
| | PI Response to Generic Letter 88-17 | 1/6/1989 |
| ENG-ME-425 | Unit 2 Steam Generator Tube Volume | 1/12/2000 |
| ENG-ME-430 | N2 Injection for RCS Draindown | 4/6/2000 |
| ENG-ME-430 | N2 Injection for RCS Draindown | 4/6/2000 |
| | B4B Reactor Vessel Level Instrumentation Sys. | Revision 4 |
| NRC IN 96-37 | Inaccurate Reactor Water Level Indication and Inadvertent Draindown During Shutdown | 6/18/1996 |
| NRC IN 96-65 | Undetected Accumulation of Gas in Reactor Coolant System and Inaccurate Reactor Water Level Indication During Shutdown | 12/11/1996 |
| USAR Section 7 | 7.10.3.4.3 Reactor Vessel Water Inventory Indication | Revision 30 |
| EC 20069 | Evaluation of Adverse Slope of Unit 2 RCGVS Piping | 5/16/2012 |
| EC 20069 | Evaluation of Adverse Slope of Unit 2 RCGVS Piping, Revision 1 | 8/22/2012 |
| NF-118087-1 | Reactor Coolant Gas Vent System | Revision 76 |
| NX-15652-22 | Head Assembly Upgrade Package RCGVS Piping Mod and Support Assembly | Revision 0 |
| NX-15652-23 | Head Assembly Upgrade Package RCGVS Piping Mod and Support Assembly | Revision 0 |
| SK-EC19795-01 | RCGVS Vent Valve | Revision 0 |
| SK-EC19795-02 | RCGVS Pipe Support 2-RCGV-1 | Revision 0 |
| SK-EC19795-03 | RCGVS Orifice Bypass Line Demolition Sketch | Revision 0 |
| WO 453395-01 | Verify No Blockage From 2RC-21-1 Through Spool Piece | May 4, 2012 |
| WO 453755-01 | Verify No Blockage From 2RC-21-1 Through Spool Piece | March 20, 2012 |
| WO453395-01 | 1-2RC-83—Measure the Level Change on RCGV Line | April 2, 2012 |
| XH-1001-3 | (No title) | April 8, 2012 |
| Calculation 25668-000P6C-000-00004 | Reactor Coolant Vent System—Unit 2 | Revision 1 |
| 50.59 Screening 3970 | Unit 2 React Vent Improvement Modification | Revision 0 |
| | Engineering at Risk Authorization | March 25, 2012 |
| EC 19795 | Design Input Checklist (Part A) | (No Date) |
| EC 19795 | Design Description—Unit 2 Reactor Head Vent Improvement Modification | Revision 0 |
| EC 19795 | Modification Control: Unit 2 Reactor Head Vent Improvement Modification | April 4, 2012 |

## LIST OF ACRONYMS USED

| | |
|---|---|
| ADAMS | Agencywide Document Access Management System |
| AR | Action Request |
| CAP | Corrective Action Program |
| CDF | Core Damage Frequency |
| CFR | Code of Federal Regulations |
| DRP | Division of Reactor Projects |
| HEP | Human Error Probability |
| IMC | Inspection Manual Chapter |
| IPEEE | Individual Plant Examination of External Events |
| LERF | Large Early Release Frequency |
| LOCA | Loss of Coolant Accident |
| LOI | Loss of Inventory |
| LOLC | Loss of Level Control |
| NCV | Non-Cited Violation |
| NOUE | Notice of Unusual Event |
| NRC | U.S. Nuclear Regulatory Commission |
| NRR | Office of Nuclear Reactor Regulation |
| PARS | Publically Available Records System |
| PSF | Performance Shaping Factor |
| RCS | Reactor Coolant System |
| RCGVS | Reactor Coolant Gas Vent System |
| RHR | Residual Heat Removal |
| RVLIS | Reactor Vessel Level Instrumentation System |
| SDP | Significance Determination Process |
| SPAR | Standardized Plant Analysis Risk |
| SRA | Senior Reactor Analyst |
| URI | Unresolved Item |

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

Sincerely,

*/RA/*

Kenneth Riemer, Branch Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000282/2012011; 05000306/2012011
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

DISTRIBUTION:
See next page

DOCUMENT NAME: Prairie Island 2012 011.docx
☒ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☒ Non-Sensitive
**To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy**

| OFFICE | RIII | N | RIII | N | RIII | E | RIII | |
|---|---|---|---|---|---|---|---|---|
| NAME | NShah:rj | | CMoore | | KRiemer | | DPassehl | |
| DATE | 09/18/12 | | 09/20/12 | | 09/20/12 | | 9/20/12 | |

***OFFICIAL RECORD COPY***

Letter to J. Sorensen from K. Riemer dated September 20, 2012

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2, NRC INSPECTION REPORT 05000282/2012011; 05000306/2012011 FOLLOWUP OF UNIT 1 NOTICE OF UNUSUAL EVENT DUE TO REACTOR COOLANT SYSTEM LEAKAGE GREATER THAN 10 GALLONS PER MINUTE

DISTRIBUTION:
Silas Kennedy
RidsNrrPMPrairieIsland Resource
RidsNrrDorlLpl3-1 Resource
RidsNrrDirsIrib Resource
Chuck Casto
Cynthia Pederson
Steven Orth
Jared Heck
Allan Barker
Christine Lipa
Carole Ariano
Linda Linn
DRPIII
DRSIII
Patricia Buckley
Tammy Tomczak
ROPreports Resource