414 Nicollet Mall
Minneapolis, Minnesota 55401

August 11, 2016

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: REPLY COMMENTS
2015 ANNUAL AUTOMATIC ADJUSTMENT OF CHARGES REPORT - ELECTRIC
DOCKET NO. E999/AA-15-611

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits these Reply Comments in response to the June 15, 2016 Comments of the Department of Commerce, Division of Energy Resources.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact me at amy.s.fredregill@xcelenergy.com or 612-215-5367 if you have any questions regarding this filing.

SINCERELY,

/s/

AMY S. FREDREGILL
MANAGER, RESOURCE PLANNING AND STRATEGY

c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY, REVIEW OF 2014-2015 ANNUAL AUTOMATIC ADJUSTMENT REPORT FOR ITS ELECTRIC OPERATION

DOCKET NO. E999/AA – 15-611

REPLY COMMENTS

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this Reply to the Minnesota Department of Commerce - Division of Energy Resources' June 15, 2016 review of our Annual Automatic Adjustment of Charges (AAA) Report for 2014-2015.

In this Reply, we respond to the Department's comments regarding (1) Prairie Island Unit 1 and Unit 2 unplanned outages, (2) the treatment of certain cost data as Public or Trade Secret, and (3) Midcontinent Independent System Operator (MISO) Section 10 administrative costs. Also, we provide additional information regarding the Company's wind curtailment protocol pursuant to the Commission's Order of June 2, 2016 in Docket E999/AA-14-579 *(2013-2014 Electric Annual Automatic Adjustment of Charges Report)*.[1] The bulk of our comments are focused on our Prairie Island plant and the treatment of replacement power costs for five unplanned outages identified in the Department's Comments. We respectfully disagree with the Department's position that these costs should be disallowed on the basis of Nuclear Regulatory Commission (NRC) inspection findings. We believe that the Company acted prudently in connection with the outages in question and that the costs associated with these outages are just, reasonable, and recoverable.

[1] Order Point 4 – Discuss in a supplement to its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits in response to manual curtailment events.

We acknowledge that 2015 was a challenging year for Prairie Island. It is important to recognize, however, that Prairie Island's capacity factor for 2014 was above average at 92.5 percent on a unit-combined basis. We further note that a significant portion of the 2015 outages were related to our development of a first-of-its-kind reactor coolant pump (RCP) seal design that was required by post-Fukushima NRC standards and that has since been adopted by utilities around the country to comply with those standards. Most importantly, we have continued to safely operate our plants without putting either our workers or our communities at risk.

We appreciate there has been and will be ongoing discussion related to whether utilities are properly incentivized to manage their fuel costs. In its June 2, 2016 Order, the Commission asked the Department to prepare and file an incentive proposal for the fuel clause adjustment (FCA).[2] The Commission's Order explained that the Department could develop this proposal either alone or jointly with other parties, and it directed that the proposal be filed within nine months, by March of 2017. We look forward to participating in this discussion. In the meantime, we respectfully ask that the Commission not tie significant financial penalties to NRC findings, which are focused on safety and at least partially rely on utilities to self-monitor and self-report for the purpose of protecting their plants, workers, and communities.

REPLY

I. Prairie Island Outages

The Department recommends that the Commission disallow most or all of the incremental costs of replacement power due to five unplanned outages at the Prairie Island nuclear power plant during the AAA report period of July 1, 2014 – June 30, 2015. The Department indicated in its comments that four of these outages were caused by the Company's non-compliance with the requirements of the NRC Code of Federal Regulations and/or vendor installation and oversight issues, and cites an NRC May 2015 Report in support of its recommendation regarding those outages. In addition, the Department included the power replacement costs of a fifth outage (March 5-6, 2015) in its calculation of total replacement energy costs, although the basis for this potential disallowance was not explained and it was not related to an NRC regulatory finding.

[2] Docket Nos. E-999/CI-03-802, E-999/AA-12-757, E-999/AA-13-599, E-999/AA-14-579.

The five outages identified by the Departments are as follows:[3]

Unit	Outage Date	Outage Issue
Prairie Island 1	12/10/14 – 12/27/14	Reactor Coolant Pump Seal
Prairie Island 1	1/26/15 – 2/12/15	Reactor Coolant Pump Seal
Prairie Island 1	4/7/15 – 5/9/15	Reactor Coolant Pump Seal
Prairie Island 2	3/5/15 – 3/25/15	Instrument Air Valve Solenoid
Prairie Island 1	3/5/15 – 3/6/15	Heater Drain Tank Level Fuse

As discussed below, we believe the replacement power costs associated with all five outages are properly recoverable as just and reasonable costs of operating a nuclear generating plant. Additionally, two of the outages identified by the Department—the third reactor coolant pump outage and the heater drain tank outage—do not relate to an NRC inspection finding and, therefore, would not qualify for disallowance under the Department's policy recommendation. Finally, while the NRC did issue an inspection finding with respect to the instrument air valve solenoid outage, the NRC did not find that the regulatory violation actually caused the outage. We therefore believe that only two of the outages identified actually fit within the policy position set out in the Department's Comments.

Below, we provide a brief background discussion of the Prairie Island nuclear plant, the nature of the NRC regulations at issue, and a policy-related discussion regarding our objections to the recommendation proposed in the Department's Comments. We then turn to the specific factual circumstances of the outages.

A. Background Information

As discussed in our January 29, 2016 Upper Midwest Resource Plan Supplement filing, Prairie Island is a cost-effective resource that benefits our customers and provides a

[3] The table reflects our interpretation of the Department's recommendation based on the total amount of refunded replacement power costs recommended. If the Department intended to identify outages other than those listed in the table above, we respectfully request the opportunity to supplement these Reply Comments.

bridge to renewable energy. It is part of the backbone of our generation fleet and is a critical component of the Company's—and the state's—carbon-reduction goals, as it produces carbon-free, base load power on an around-the-clock basis. Prairie Island Unit 1, for example, achieved 434 days of continuous operation as of August 10, 2016, and Unit 2 achieved a capacity factor of 100 percent in 2014—both of which are significant operational achievements.

At the same time, we believe it is reasonable to experience a certain number of unplanned outages due to the safety standards of both the NRC and nuclear industry. These outages are part and parcel of operating a nuclear plant (or any electrical generating plant), which is one of the reasons we have a diversified generation fleet.[4] Finally, given the safety-first priority of the NRC, we believe it is reasonable to expect that some of our nuclear plant outages will relate to NRC findings like those identified by the Department—all of which were classified by the NRC as having "very low safety significance."

B. NRC Regulations & Findings

The Department's overall position regarding our nuclear fleet appears to be that recovery should be disallowed for any outage that has a corresponding NRC inspection finding. We do not believe this recommendation is consistent with the just and reasonable standard that should be used to evaluate our costs. As explained in the next section of these comments, we believe that our actions in connection with each of the five outages were reasonable under the circumstances and that our costs are therefore just, reasonable, and recoverable. We also believe the use of NRC inspection findings to bar the recovery of costs could conflict with the safety priorities of both the Company and the NRC. For these reasons, we respectfully disagree with the Department's recommendation.

NRC regulations are focused on safety. Safety is also the Company's first priority for nuclear generation, and it is an ever-present consideration in all the work we do. Compliance with our NRC obligations is a core value of the Company and our nuclear operations team. We have worked hard to build a strong safety culture at our nuclear facilities, and we strive to comply with all regulations at all times.

We do not believe that NRC safety findings should be used to bar the recovery of replacement power costs. The purpose of the NRC's standards is to bring plants offline and to identify safety issues *before* significant risks materialize. To that end, we—along

[4] We note that independent power producers will not agree to paying for replacement power costs because they too expect that outages will occur as a normal part of operating an electrical generating plant.

with other utilities—frequently self-report issues to the NRC, and we believe this reporting and our focus on safety should be encouraged. The use of NRC findings to bar the recovery replacement power costs could negatively impact these safety practices by tying financial penalties to safety-driven decisions and actions. Additionally, both operators and the NRC often work backward from unplanned outages to conduct a causal analysis, and it is commonplace for this process to result in the discovery of inspection findings of "very low safety significance." The Department's recommendation—taken to its logical end—could put plant operators in the position of risking a cost disallowance each time the plant is brought offline as a result of potential safety concerns.

Additionally, industry experience and data demonstrate that 100 percent compliance with NRC regulations is not realistic or possible. In fact, the NRC's website explains that its "enforcement program is based on the recognition that violations occur in a variety of activities and have varying levels of significance."[5] Likewise, the NRC Reactor Oversight Process manual states that:

> As in all industrial activities, nuclear power plants are not error-free or risk-free. <u>Equipment problems and human errors will occur</u>. Each performance indicator determines acceptable levels of operation within substantial safety margins.[6]

In other words, NRC findings of "very low safety significance"—like those associated with the outages at issue in this docket—are commonplace in the industry. In fact, NRC data demonstrate that there were 867 NRC findings across the industry in 2015 and that there were more than 1,000 findings in some earlier years such as 2011. These numbers—along with the NRC's own statements concerning the acceptable levels of errors—reflect the purpose of the NRC's standards, which is to identify safety issues *before* significant risks materialize.

As explained in the Reactor Oversight Process manual, a finding of "very low safety significance" does not result in either a notice of violation or any formal enforcement action.[7] The following graphic shows the increasing safety significance of inspection findings like the ones cited by the Department, both of which were Green:

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[5] http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pro.html
[6] Reactor Oversight Process, page. 4 (emphasis added).
[7] Reactor Oversight Process, page. 8.

Although we strive to comply with all NRC safety regulations at all times, we do not believe that perfect compliance and the elimination of all "Green" inspection findings would be possible even with a limitless operating budget.

In short, we believe that disallowing the recovery of outage costs simply because there was an associated NRC finding misapplies the intent of the NRC's safety regulations and imposes a standard that is unattainable by any nuclear operator. We understand our stakeholders' desire for an incentive mechanism in connection with the FCA. We also understand that the Department is working on an incentive proposal in response to the Commission's June Order, and we look forward to participating in that discussion. Our concern with the Department's present recommendation is that it ties financial penalties to NRC findings, which are commonplace in the industry, are focused on safety, and at least partially rely on utilities to self-monitor and self-report for the purpose of protecting their plants, workers, and communities. For these reasons, in addition to those discussed below, we respectfully request that Commission allow recovery of the replacement power costs at issue.

C. Outage Details

In addition to our policy-based concerns with the Department's recommendation, we also believe the Department has recommended disallowance for certain outages that were *not* directly related to, or caused by, NRC inspection findings and therefore would *not* be subject to disallowance even under the Department's position. We further believe that we acted prudently under the circumstances of each outage and that, as a result, our replacement power costs for those outages are just and reasonable. We discuss each of the outages in detail below.

1. Outages 1-3 – Reactor Coolant Pump Seals

Overview of the Seals Project: In the fall of 2014, the Company implemented a new design for the reactor coolant pump (RCP) seals that was intended to reduce the probability of an event causing nuclear fuel damage, improve the reliability of the seal package, and extend the operating life of the seals before replacement was required. In the past, we had experienced seal performance issues due to foreign material from the reactor makeup system and particulates from RCPs themselves that occasionally caused seal failures. The Company had considered alternative seal designs as early as 2002, but the cost of redesigning and installing the seals outweighed the projected operational improvements. Post-Fukushima, however, the Company's enhanced probabilistic risk assessment (PRA) models demonstrated that the original Westinghouse seals were among the most frequent contributors to core damage. As a result, the NRC attributed a high level of risk to the RCP seals, and the Company committed to an alternative RCP seal design in 2012 when Prairie Island submitted a license amendment request to adopt a performance-based fire protection standard 10 CFR 50.48(C) (National Fire Protection Association 805).

After considering various options, the Company ultimately selected the Flowserve N-9000 seal as the best option from risk reduction and operational performance improvement perspectives. Although the seal had never before been installed in a Westinghouse RCP, it was a proven design that had an extensive operating history in other kinds of pumps, which was not the case for the alternative seal designs that the Company considered in response to the new NRC requirements. The Company therefore concluded that the N-9000 seal was the best option for this first-of-its kind installation.

As described below, the new seals proved to be unusually susceptible to foreign material in the RCP system and led to three unplanned outages in late 2014 and early 2015. While the first two outages involved a vendor installation issue, the fundamental problem was that the new seal had to be redesigned because it was susceptible even to smaller particles of foreign material that were present in the RCP under normal operating conditions. Following this redesign, the seal has remained in operation since April 2015, and the final design has been adopted by a number of utilities across the country.

Installation & Outages: In December 2014, during the 1R29 refueling outage, the new seal (Seal 12-1) was installed at Unit 1. Almost immediately following startup, the seal began to degrade, which resulted in a forced outage on December 10, 2014.

On December 13, Seal 12-1 was removed from the RCP and borescope inspections of the pump internals were performed as part of the Company's causal analysis. Additionally, Seal 12-1 was shipped to Flowserve's "hot lab" in Memphis, Tennessee for inspection, which revealed that the failure was due to wear to the seal caused by foreign material inside the seal. In particular, Flowserve identified an unusual quantity of metallic debris in the seal and an absence of mechanical interference inside the seal itself, suggesting that the foreign material originated outside the seal package. The foreign material was comprised of flake-like particles ranging from approximately

10-200 microns in diameter that had worn circular grooves around the stationary faces of the seal stages that led to the destaging of the seal.

A troubleshooting team was assembled to assess the cause of the outage and to determine how best to return the plant to service. The team ultimately concluded that the foreign material likely originated in the seal bypass line, which had been reconfigured as part of the installation in late 2014. The Company's root cause analysis team confirmed this by reviewing photographs from November 2014 refueling outage that were taken in the RCP #12 seal area. On the basis of those photographs, the team concluded that the foreign material was introduced by Flowserve's use of band-type saws to cut piping during the installation of the seals without adequate Foreign Material Exclusion (FME) controls.

Because the Company's new seal design was going to be used by other plants around the country to comply with post-Fukushima regulations, the Company received assistance not only from Westinghouse and Flowserve but also from multiple industry experts from utilities around the country. Based on the advice of these experts and the seal vendor, the Company decided to remove the foreign material from the seal and the top face of the RCP's radial bearing and then replace the seals to bring the plant back online. The replacement seal was installed, and Unit 1 resumed operation on December 27, 2014 with Seal 12-3 in place.[8]

Similar but slower degradation occurred with Seal 12-3, which resulted in a second outage on January 26, 2015. The troubleshooting team concluded after this outage that the new seal design was unusually susceptible to much smaller particles of foreign material, which the Company had not experienced with previous RCP seals. To address this issue, an aggressive series of flushes of the RCP was performed. Physical evidence was collected and quarantined from each flush, and a total of 51 flush evolutions were performed, using approximately 23,000 gallons of water.

Following this extensive series of flushes, Seal 12-4 was installed on February 5, 2015. Again, it began to degrade soon after startup, but the degradation rate was slower than both of the previous seal failures. The degradation resulted in the final RCP-related outage on April 7, 2015. While the degradation was again due to foreign material found in the seal, the debris was present in "orders of magnitude lower quantities" than the previous outages due to the aggressive flushes that had been performed.

[8] Seal 12-2 was damaged during installation, and the unit never ascended with Seal 12-2 in place.

After this outage, the Company concluded that the seal design had to be modified in order to address the susceptibility of the new seal to unusually small particles of foreign material that are present under normal operating conditions and as a result of normal RCP operation. Specifically, the seal face material was changed from slotted carbon to tungsten carbide, which has proven more resilient to the existence of foreign material. Additionally, the Company implemented a new "frothing flush" method to remove even finer particles of foreign material from the RCP system. The new seal design has remained in service without failure, and other utilities around the country are now using the same design to ensure that foreign material from normal operations does not degrade the RCP seals and result in outages.

Recoverability of Costs: We believe the replacement power costs associated with these outages are just, reasonable, and recoverable. Difficult and novel engineering problems—like the development of new equipment to comply with new, post-Fukushima requirements—frequently involve a certain amount of trial and error. After the first outage, we received advice from multiple industry experts and reasonably concluded that the seal should be replaced after removing foreign material from the RCP's radial bearing. This decision was driven by the Company's interest in returning the plant to service as safely, quickly, and efficiently as possible in order to minimize replacement power costs for our customers.

After the second outage, we fully flushed the RCP and removed any foreign material introduced as a result of the vendor installation issue. As a result, we do not believe the third RCP outage was caused by the installation, nor has there been any NRC finding to that effect. The NRC report cited by the Department was dated May 6, 2015 and documents an inspection that was completed on March 31, 2015. It therefore does not apply to the third RCP seal-related outage that occurred from April 7 to May 9, 2015. In fact, the NRC detailed its evaluation of the third outage in its August 5, 2015 Integrated Inspection Report and noted that "no findings were identified" in connection with the outage. The full NRC Integrated Inspection Report is included as Attachment A to this Reply.

We believe our actions in connection with the RCP seal outages were appropriate under the circumstances known to the Company at the time of each outage. We therefore believe that the replacement power costs for these outages are just and reasonable and that the Company should be permitted to recover those costs through the FCA.

2. *Outage 4 –Solenoid Valve (March 5 – 25, 2015)*

Prairie Island Unit 2 was unexpectedly forced off-line on March 5, 2015, due to the failure of a solenoid valve. The resulting outage lasted until March 25, 2015.

A solenoid valve is an electromechanically operated valve that is controlled by an electric current through a solenoid. Electrical current is applied to the solenoid to control the valve's position (open or closed). During normal plant operations, the solenoid valve in question is in the open position to allow air to be supplied from the plant's instrument air system to other components inside containment. During certain plant events, the solenoid valve is designed to close in order to prevent leakage from inside the containment area.

When the solenoid valve in question failed, the valve closed and prevented air from being supplied to other components inside the containment that is necessary to support normal plant operations. This means the normal method of cooling equipment inside containment was not available, making it was necessary to switch to an alternate method.

While the NRC report referenced by the Department concluded that there was a violation of the requirements of 10 CFR 50.49, "Environmental Qualification (EQ) of Electric Equipment Important to Safety for Nuclear Power Plants," the NRC did not conclude that the violation was the cause of the component failure and the resulting forced outage.

Under the plant's EQ Program to meet 10 CFR 50.49, useful life on individual components are established and followed. The EQ Program component life, which takes into account the component's capability to operate under harsher accident conditions (higher radiation, heat and humidity) is shorter than the duration a component would otherwise be expected to operate if the same component only operated under normal plant operating conditions (relatively lower radiation, heat and humidity).

The solenoid valve in question had only operated under normal plant operating conditions and had shown no indications that its performance was declining. While the NRC found that the valve had gone beyond its EQ Program component life, it did not comment on the capability of the component to perform under normal plant conditions and whether the solenoid valve's failure under normal plant conditions should have been predicted or expected. In fact, the solenoid valve operated effectively for a number of years past its EQ Program component life. When it failed, the Company's root cause evaluation team considered whether or not preventative maintenance should have detected the potential for failure prior to it occurring, and the team concluded that it could not have been predicted and that the preventative maintenance schedule was not a factor that contributed to the outage.

We therefore do not believe any disallowance of replacement power costs associated with this outage is appropriate.

3. *Outage 5 – Heater Drain Tank Level Fuse (March 5-6, 2015)*

On March 5, 2015, the heater drain tank pumps locked out due to a low heater drain tank level indication, causing a reduction in power to 95 percent for 30 hours. However, the NRC did not cite an NRC safety violation in relation to this outage.

The cause of the low-level indication was a failed fuse on the heater drain tank level indicator. The fuse had been replaced due to low voltage on November 13, 2014. Past experience has demonstrated that a four-year replacement frequency is adequate for preventive maintenance. The operations team concluded that this instance was due to a premature part failure. The fuse was replaced, and the unit resumed normal operation on March 6, 2015.

The costs associated with this outage appear to have been included in the Department's calculation of replacement power costs that should be disallowed. The Department did not, however, explain why it believed that replacement power costs associated with this outage are not properly recoverable. Additionally, there has been no NRC finding or violation associated with this outage. Accordingly, we believe that costs associated with this outage are properly recoverable not only for the policy reasons discussed above, but also because this outage does not appear to meet the characteristics identified by the Department as disqualifying it for cost recovery purposes.

D. Summary of the Company's Position Regarding the Five Outages Identified by the Department

In summary, the Company respectfully disagrees with the Department's position that NRC safety regulations should be used to disallow the recovery of replacement power costs for plant outages. We also maintain that some of the outages identified by the Department—specifically, the third RCP outage, the solenoid outage, and the heater drain take fuse outage—were not actually caused by noncompliance with NRC regulations. As to the remaining outages, we believe that our actions and costs should be judged against a standard of reasonableness rather than perfect compliance with NRC safety regulations. Under the circumstances described above, we believe that our actions—and therefore our costs—were reasonable. We therefore request that the Commission allow recovery of these costs.

II. Trade Secret Data

In their comments, the Department requested utilities to address the Public or Trade Secret treatment of the following data:

- Table 3 and Chart 2 – Utility Cost Projections vs Actual Costs per MWh for 2015

- The Cost of Replacement Power for Prairie Island Outages in 2014 – 2015

We agree that the 2015 actual cost data in Table 3 and Chart 2 can be treated as Public data.

We continue to maintain that our estimated cost of replacement power should be treated as Trade Secret data.

III. MISO Day 1 Charges

We agree with the Department's recommendations to continue the following reporting items:

- provide in the initial filing of all future electric AAA Reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used and support for why the allocator is reasonable; and
- provide information to support MISO Schedule 10 cost increases of five percent or higher over the prior year costs, including explanation of benefits received by customers for these added costs.

IV. Wind Curtailment

In the Commission's June 2, 2016 Order in Docket No. E999/M-14-579, Ordering Point No. 4 requires the Company to:

> "… discuss in a supplement to its FYE15 AAA report whether and why it is still reasonable to curtail wind facilities that are receiving Production Tax Credits, in response to Manual Curtailment Events."

The Company has detailed wind curtailment guidelines in place to ensure that wind resources are managed economically and for the reliability of the system, consistent with the terms of the related purchased power contracts. NSP Generation Control and Dispatch (Dispatch) will take a variety of actions, including wind curtailment, to meet North American Electric Reliability Corporation (NERC) reliability standards. While operating reliability is its primary goal, Dispatch also strives to minimize total generation costs including the consideration of wind farm curtailment costs. Specific curtailment procedures are in place that take into account how the asset is registered in the MISO Market, whether the wind farm is equipped with setpoint control equipment, which wind farms are registered as Dispatchable Intermittent Resources (DIR), and which are Intermittent. A curtailment matrix has been established and is maintained that lists CP Node location, contract price, production tax credit status, compensable curtailment threshold, and curtailment for economics. The list is organized from highest to lowest curtailment threshold, that is, the market price below which it is economic to curtail if curtailment is compensable.

For DIR units, MISO performs a 10-minute forecast every five minutes. This forecast is used as the maximum limit for the wind farm in the Unit Dispatch System. MISO sends five-minute dispatch instructions to DIR wind farms. When Locational Marginal Pricing (LMP) drops below the offer price of the DIR unit, the farm is automatically dispatched down. The setpoint is sent to the DIR wind farm, and the facility is automatically curtailed. It should be noted that intermittent units are not equipped with setpoint control, and not all DIR farms are equipped with setpoint controls. In such situations, a phone call or e-mail is required to initiate curtailment. When these units must be curtailed, a phone call or e-mail to the wind farm operator is required, which can add time to the process.

While the Company's curtailment guidelines and practices place a priority on curtailment of the highest-cost wind facility, in some instances the curtailment of a wind farm that still qualifies for Production Tax Credits is unavoidable. This may be due to storm-related events (which occur rather frequently in southwestern Minnesota), or transmission line maintenance work (planned and unplanned). These types of events were described in detail in our response to Information Request DOC-33 in conjunction with our 2013-2014 AAA Report (Docket No. E999/AA-14-579).

CONCLUSION

The Company appreciates this opportunity to submit its Reply to the Department's review. Through this Reply, we have worked to provide additional information in response to the issues raised by the Department. We respectfully request that the Commission accept and approve Xcel Energy's FYE15 Electric AAA Report as supplemented by this Reply.

Dated: August 11, 2016
Northern States Power Company

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

August 5, 2015

EA 15-054

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

SUBJECT: PRAIRIE ISLAND NUCLEAR GENERATING PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000282/2015002;
05000306/2015002 AND EXERCISE OF ENFORCEMENT DISCRETION

Dear Mr. Davison:

On June 30, 2015, 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 July 24, 2015, with you and other members of your staff.

Three NRC-identified findings of very low safety significance (Green) and one Severity Level IV violation were identified during this inspection. The issues were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. Additionally, two licensee-identified violations for which enforcement discretion was granted are listed in Section 4OA7 of this report.

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

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

Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

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

Enclosure:
IR 05000282/2015002; 05000306/2015002
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 No:	05000282/2015002; 05000306/2015002
Licensee:	Northern States Power Company, Minnesota
Facility:	Prairie Island Nuclear Generating Plant, Units 1 and 2
Location:	Welch, MN
Dates:	April 1 through June 30, 2015
Inspectors:	L. Haeg, Senior Resident Inspector K. Stoedter, Senior Resident Inspector P. LaFlamme, Resident Inspector J. Corujo-Sandin, Engineering Inspector N. Feliz-Adorno, Senior Engineering Inspector M. Jeffers, Engineering Inspector L. Kozak, Senior Reactor Analyst M. Phalen, Senior Health Physicist A. Shaikh, Engineering Inspector
Approved by:	K. Riemer, Chief Branch 2 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000282/2015002, 05000306/2015002; 04/01/2015–06/30/2015, Prairie Island Nuclear Generating Plant, Units 1 and 2; Identification and Resolution of Problems, Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three U.S. Nuclear Regulatory Commission (NRC)-identified findings and one Severity Level IV violation were identified during this inspection. The findings and violation were considered non-cited violation (NCVs) of NRC regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. 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.

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance and an associated non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to ensure the design requirements of the #12 battery charger were maintained. Specifically, the licensee failed to address the impact that previously identified additional electrical loads had on the design capacity of the battery chargers from May of 2010 until April of 2015.

The inspectors determined that the failure to maintain the design basis for the battery charger was contrary to 10 CFR 50 Part 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency. The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee failed to account for the additional electrical load of the inverters on the #12 battery charger. This additional load exceeded the battery charger's design capacity and as a result, the licensee could not demonstrate that the #12 battery charger would be capable of responding to initiating events to prevent undesirable consequences. In accordance with Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," issued June 19, 2012, and Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," issued June 19, 2012, the inspectors answered "Yes" to Question 2 of the Mitigating SSCs and Functionality screening questions because the finding represented a loss of function to the #12 battery charger. Thus the inspectors consulted the regional senior reactor analyst (SRA) for additional assistance and the finding was determined to be of very low safety significance (Green). No cross-cutting aspect was assigned to this issue as the actions taken in 2011 were not reflective of current performance.
(Section 4OA2.4.b.(1))

Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the licensee’s failure to promptly correct a condition adverse to quality. Specifically, the licensee failed to correct a non-conforming issue for the #12 battery that was discovered in February 2011.

The inspectors determined that the failure to correct the non-conformance in a timely manner was contrary to 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” and was a performance deficiency. The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Equipment Performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee did not take timely corrective actions to resolve the #12 battery non-conformance. Additionally, no corrective action was taken to correct the occurrence of the inverters’ AC circuit breakers tripping of the normal load and becoming an additional load on to the DC system; thereby causing the battery to be non-conforming. In accordance with Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” issued June 19, 2012, and Appendix A, “The Significance Determination Process for Findings At-Power,” Exhibit 2, “Mitigating Systems Screening Questions,” issued June 19, 2012, the inspectors answered “No” to all of the questions. The inspectors confirmed that the finding did not result in a loss of operability or functionality per IMC 0326, “Operability Determination & Functionality Assessments for Conditions Adverse to Quality or Safety,” since the capacity of the battery had been tested above the 88.5 percent capacity factor per battery calculation and evaluation. Therefore, this finding was of very low safety significance (Green). The inspectors determined the finding was cross-cutting in the Problem, Identification and Resolution, Resolution area because of the licensee’s failure to implement effective corrective actions to restore operability of the #12 battery. [P.3] (Section 4OA2.4.b.(2))

Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” on October 13, 2014, for the licensee’s failure to ensure the design requirements of the fire protection program were maintained. Specifically, the licensee had not ensured that Group E pressurizer heaters would continue to operate following a fire in Fire Area 32 (the Unit 1 side of the auxiliary feedwater pump room). As a result, the licensee was unable to ensure that the Unit 1 reactor would be able to achieve and maintain a cold shutdown condition following a fire in this area.

The inspectors determined that the failure to ensure the design requirements of the fire protection program were maintained was contrary to 10 CFR 50, Appendix B, Criterion III, “Design Control,” and was a performance deficiency. The finding was more than minor because it was associated with the Protection from External Factors attribute of the Mitigating Systems cornerstone. The finding also impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors utilized IMC 0609, Attachment 4, “Initial Characterization of Findings,” dated June 19, 2012, and determined that this finding was best assessed for safety significance by using IMC 0609, Appendix F, “Fire Protection Significance Determination Process.” The inspectors used IMC 0609, Appendix F, Attachment 1, “Fire Protection SDP Phase 1 Worksheet,” dated September 20, 2013, and assigned a Post-Fire Safe Shutdown fire inspection finding category to the issue per Step 1.2. Based upon the information contained in Step 1.3 of IMC 0609, Appendix F, Attachment 1, the finding was determined to be of very low safety significance because any fire related damage to the Group E pressurizer heater cables did not impact the licensee's ability to reach and maintain a safe shutdown condition (either hot or cold). No cross-cutting aspect was assigned to this issue since the missed opportunities to identify this issue occurred more than three years ago and were not reflective of current performance. (Section 4OA3.6)

Cornerstone: Other

Severity Level IV. The inspectors identified a Severity Level (SL) IV NCV of 10 CFR 50.72(b)(3)(ii)(B) due to the licensee's failure on August 8, 2014, to report an unanalyzed condition within eight hours of discovery. Specifically, the lack of fuse protection for the emergency bearing oil pump control circuitry created an unanalyzed condition due to the potential for a fire that impacted the licensee's safe shutdown capabilities.

The inspectors determined that the failure to submit a report required by 10 CFR 50.72 for the unanalyzed condition described above was a performance deficiency. The inspectors determined that this issue had the potential to impact the regulatory process based, in part, on the information that 10 CFR 50.72 reporting serves. Since the issue impacted the regulatory process, it was dispositioned through the Traditional Enforcement process. The inspectors determined that this issue was a Severity Level IV violation based on Example 6.9.d.9 in the NRC Enforcement Policy. Example 6.9.d.9 specifically states, "A licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73." Because the licensee identified the technical issue as part of their NFPA-805 transition process, and no additional or separate NRC-identified or self-revealed more-than-minor Reactor Oversight Process findings were noted, there was no cross-cutting aspect associated with this violation. (Section 4OA3.4.b)

Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at full power. On April 7, 2015, operations personnel shut down the Unit 1 reactor to replace the seal on the #12 reactor coolant pump. Unit 1 returned to power on May 9, 2015, following the seal replacement. On May 31, 2015, operations personnel manually tripped the Unit 1 reactor after experiencing a sudden loss of the 11 condensate pump. The licensee determined that the 11 condensate pump tripped due to a problem internal to the pump's motor. The Unit 1 reactor returned to power on June 3, 2015. After completing power ascension activities, the Unit 1 reactor operated at full power for the remainder of the inspection period.

Unit 2 began the inspection period operating at full power. On April 3, 2015, operations personnel manually tripped the Unit 2 reactor following the unexpected loss of the 21 feedwater pump. The licensee returned Unit 2 to power the following day after determining that the 21 feedwater pump had locked out due to a pressure switch internal failure. The licensee replaced the failed pressure switch and performed an extent of condition review to verify that the remaining pressure switches were not experiencing a similar failure mechanism. The Unit 2 reactor operated at full power until June 7, 2015, when the reactor automatically tripped due to a low main turbine oil pressure condition. The licensee determined that the low oil pressure condition was caused by a weld failure on a turbine oil pipe. Once the weld was repaired, the licensee returned Unit 2 to power on June 13, 2015. Unit 2 operated at its full power level for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current (AC) Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate AC power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- coordination between the TSO and the plant during off-normal or emergency events;
- explanations for the events;
- estimates of when the offsite power system would be returned to a normal state; and
- notifications from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

.2 External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Updated Safety Analysis Report (USAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also walked down underground bunkers/manholes subject to flooding that contained multiple train or multiple function risk-significant cables. The inspectors also reviewed the abnormal operating procedure (AOP) for mitigating the design basis flood to ensure it could be implemented as written. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one external flooding sample as defined in IP 71111.01–05.

b. Findings

No findings were identified.

.3 Readiness For Impending Adverse Weather Condition—Heavy Rainfall Condition

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with predicted heavy rainfall and rises in local river and lake levels. The evaluation included a review to check for deviations from the descriptions provided in the USAR for features intended to mitigate the potential for flooding/water intrusion. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during the heavy rainfall condition or allow water ingress past a barrier. The inspectors also reviewed the AOP and compensatory measures for heavy rainfall to ensure they could be implemented as written. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01–05

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- D5 emergency diesel generator (EDG); and
- 121 motor-driven cooling water pump (MDCLP).

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

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Areas 10 and 79 – Bus 112 and Train A Event Monitoring Room;
- Fire Areas 31 and 32 – Auxiliary Feedwater Pump Rooms;
- Fire Area 80 – Bus 121 Switchgear Rooms; and
- Fire Area 127 – Bus 211 and 212 Switchgear Room.

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

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

b. Findings

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On June 23, 2015, the inspectors observed fire brigade activation for an unannounced drill for a simulated fire near the Unit 2 main feedwater pumps. Based on this observation, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the USAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- D5/D6 Diesel Generator Building.

Documents reviewed during this inspection are listed in the Attachment to this report. This inspection constituted one internal flooding sample as defined in IP 71111.06–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On May 6, 2015, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

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

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation during Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On April 7, 2015, the inspectors observed the Unit 1 control room operators shutting down the reactor for a planned maintenance outage. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;

- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

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

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

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Unit 1 charging system; and
- Nuclear steam supply system.

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

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

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

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

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Emergent work on the D6 EDG following a surveillance test failure;
- Emergent work on the intake screenhouse emergency bypass gate control circuitry; and
- Risk assessment following identification of lowering inventory within the 11 refueling water storage tank.

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

Documents reviewed during this inspection are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted three samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following operability evaluations (OPRs) and operability related issues:

- OPR 1270104, Revision 7–Unit 1 Inverter Input Breaker Trips Open during EDG Loading;
- Foreign material found inside #12 reactor coolant pump;
- OPR 1477721, Revision 0–Under Deposit Corrosion Found on 21 Containment Fan Coil Unit;
- OPR1477721. Revision 1–Under Deposit Corrosion Found on 21 Containment Fan Coil Unit;
- OPR 1482226, Revision 0 – RHR Void Identified at Location 2RH–26 and 2RH–09; and
- EC 25300, Pipe Stress Review of Spent Fuel Pool Purification Piping.

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

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

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- 12 reactor coolant pump testing following the #3 pump seal replacement;
- 11 annulus sump pump testing following a pump replacement;

- 12 reactor coolant pump testing following replacing the #1 and #2 pump seals with the Mayer Groove seal design;
- D1 EDG testing following planned maintenance;
- D6 EDG testing following emergent maintenance;
- 21 auxiliary building make-up air damper planned maintenance;
- 121 motor driven cooling water pump automatic air vent pipe repair; and
- Unit 1 anticipated transient without scram (ATWS) mitigation system actuation circuitry (AMSAC) card replacement.

These activities were selected based upon the SSCs ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unplanned Unit 2 outage that began on April 3, 2015, and continued through April 4, 2015. The outage occurred following an unexpected shut down of the 21 feedwater pump and a subsequent manual reactor trip. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing outage related work activities.

The inspectors observed activities that occurred following the reactor trip and during the subsequent reactor startup. The inspectors also monitored maintenance activities associated with the 21 feedwater pump. The licensee determined that the 21 feedwater pump shutdown was caused by an internal failure of a feedwater pump pressure switch. The licensee replaced the failed pressure switch and returned the 21 feedwater pump to service. Additional information regarding this event is documented in Section 4OA3 of this IR. The inspectors performed daily corrective action document reviews to verify that the licensee was identifying and resolving outage related problems in accordance with procedures. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one other outage sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

.2 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for a planned Unit 1 outage that began on April 7, 2015, and continued through May 9, 2015. The purpose of this outage was to replace the #12 reactor coolant pump seal. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one other outage sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

.3 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unplanned Unit 1 outage that began on May 31, 2015, and continued through June 3, 2015. This outage occurred following an unexpected shut down of the 11 condensate pump and a subsequent manual reactor trip. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing outage related work activities.

The inspectors observed activities that occurred following the reactor trip and during the subsequent reactor startup. The inspectors also monitored maintenance activities associated with the 11 condensate pump. The inspectors performed daily corrective action document reviews to verify that the licensee was identifying and resolving outage related problems in accordance with procedures. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one other outage sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

.4 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unplanned Unit 2 outage that began on June 7, 2015, and continued through June 13, 2015. This outage occurred following an automatic trip of the Unit 2 turbine and reactor in response to a turbine lube oil low pressure condition. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed activities that occurred following the reactor trip and during the subsequent reactor startup. The inspectors also monitored maintenance activities associated with the turbine lube oil system. The licensee determined that the turbine lube oil low pressure condition was caused by the failure of a pipe weld within the lube oil system. The licensee was continuing to evaluate the cause of the weld failure at the conclusion of the inspection period. The inspectors performed daily corrective action document reviews to verify that the licensee was identifying and resolving outage related problems in accordance with procedures. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one other outage sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

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

- SP 1001AA–Daily Reactor Coolant System Leakage Test (routine);
- SP 1071.4–Unit 1 Containment Integrated Leakage Test (routine);
- SP 1155A–Component Cooling Water System Quarterly (In-service);
- SP 1305–D2 Diesel Generator Monthly Slow Start Test (routine);
- SP 1412–11 Battery Charger Load Test (routine);
- SP 1413–12 Battery Charger Load Test (routine); and
- SP 2089B–Train B Residual Heat Removal Pump Suction from the Refueling Water Storage Tank Quarterly (routine).

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate OPR or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted six routine surveillance testing samples and one in-service testing sample as defined in IP 71111.22, Sections –02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on May 5, 2015, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This inspection constituted a partial sample as defined in IP 71124.01–05.

.1 Risk-Significant High-Radiation Area and Very-High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors discussed with the Radiation Protection Manager the controls and procedures for high-risk, high-radiation areas, and very-high radiation areas. The inspectors discussed methods employed by the licensee to provide stricter control of a very-high radiation area access as specified in 10 CFR Part 20.1602, “Control of Access to Very-High Radiation Areas,” and Regulatory Guide 8.38, “Control of Access to High and Very-High Radiation Areas of Nuclear Plants.” The inspectors assessed whether any changes to licensee procedures substantially reduced the effectiveness and level of worker protection.

The inspectors discussed the controls in place for special areas that had the potential to become very-high radiation areas during certain plant operations with first-line health physics supervisors (or equivalent positions having backshift health physics oversight authority). The inspectors assessed whether these plant operations required communication beforehand with the health physics group, so as to allow corresponding timely actions to properly post, control, and monitor the radiation hazards including re-access authorization.

The inspectors evaluated licensee controls for very-high radiation areas and areas with the potential to become very-high radiation areas to ensure that an individual was not able to gain unauthorized access to the very-high radiation areas.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

This inspection constituted one complete sample as defined in IP 71124.06–05.

.1 Inspection Planning and Program Reviews (02.01)

Event Report and Effluent Report Reviews

a. Inspection Scope

The inspectors reviewed the Radiological Effluent Release Reports issued since the last inspection to determine if the reports were submitted as required by the Offsite Dose Calculation Manual/TSs. The inspectors reviewed anomalous results, unexpected trends, or abnormal releases identified by the licensee for further inspection to determine if they were evaluated, were entered in the CAP, and were adequately resolved.

The inspectors selected radioactive effluent monitor operability issues reported by the licensee as provided in the Effluent Release Reports, to review these issues during the on-site inspection, as warranted, given their relative significance and determine if the issues were entered into the CAP, and adequately resolved.

b. Findings

No findings were identified.

Offsite Dose Calculation Manual and Final Safety Analysis Report Review

a. Inspection Scope

The inspectors reviewed USAR descriptions of the radioactive effluent monitoring systems, treatment systems, and effluent flow paths so they could be evaluated during inspection walkdowns.

The inspectors reviewed changes to the Offsite Dose Calculation Manual made by the licensee since the last inspection against the guidance in NUREG-1301 and 0133, and Regulatory Guides 1.109, 1.21, and 4.1. When differences were identified, the inspectors reviewed the technical basis or evaluations of the change during the on-site inspection to determine whether they were technically justified, and maintained effluent releases as-low-as-reasonably-achievable.

The inspectors reviewed licensee documentation to determine if the licensee had identified any non-radioactive systems that had become contaminated as disclosed either through an event report or the Offsite Dose Calculation Manual since the last inspection. This review provided an intelligent sample list for the on-site inspection of any 10 CFR 50.59 evaluations, and allowed a determination if any newly contaminated systems had unmonitored effluent discharge paths to the environment, whether any required Offsite Dose Calculation Manual revisions were made to incorporate these new pathways, and whether the associated effluents were reported in accordance with Regulatory Guide 1.21.

b. Findings

No findings were identified.

Groundwater Protection Initiative Program

a. Inspection Scope

The inspectors reviewed reported groundwater monitoring results and changes to the licensee's written program for identifying and controlling contaminated spills/leaks to groundwater.

b. Findings

No findings were identified.

Procedures, Special Reports, and Other Documents

a. Inspection Scope

The inspectors reviewed Licensee Event Reports (LERs), event reports and/or special reports related to the Effluent Program issued since the previous inspection to identify any additional focus areas for the inspection based on the scope/breadth of problems described in these reports.

The inspectors reviewed the Effluent Program implementing procedures, particularly those associated with effluent sampling, effluent monitor set-point determinations, and dose calculations.

The inspectors reviewed copies of licensee and third party (independent) evaluation reports of the Effluent Monitoring Program since the last inspection to gather insights into the licensee's program, and aid in selecting areas for inspection review (smart sampling).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down selected components of the gaseous and liquid discharge systems to evaluate whether equipment configuration and flow paths aligned with the documents reviewed in 02.01 above, and to assess equipment material condition. Special attention was made to identify potential unmonitored release points, building alterations that could impact airborne or liquid effluent controls, and ventilation system leakage that communicated directly with the environment.

For equipment or areas associated with the systems selected for review that were not readily accessible due to radiological conditions, the inspectors reviewed the licensee's material condition surveillance records, as applicable.

The inspectors walked down filtered ventilation systems to assess for conditions such as degraded high-efficiency particulate air/charcoal banks, improper alignment, or system installation issues that would impact the performance or the effluent monitoring capability of the effluent system.

As available, the inspectors observed selected portions of the routine processing and discharge of radioactive gaseous effluent (including sample collection and analysis) to evaluate whether appropriate treatment equipment was used and the processing activities aligned with discharge permits.

The inspectors determined if the licensee had made significant changes to their effluent release points (e.g., changes subject to a 10 CFR 50.59 review or require NRC approval of alternate discharge points).

As available, the inspectors observed selected portions of the routine processing and discharging of liquid waste (including sample collection and analysis) to determine if appropriate effluent treatment equipment was being used, and that radioactive liquid waste was being processed and discharged in accordance with procedure requirements and aligned with discharge permits.

b. Findings

No findings were identified.

.3 Sampling and Analyses (02.03)

a. Inspection Scope

The inspectors selected effluent sampling activities, consistent with smart sampling, and assessed whether adequate controls had been implemented to ensure representative samples were obtained (e.g. provisions for sample line flushing, vessel recirculation, composite samplers, etc.).

The inspectors selected effluent discharges made with inoperable (declared out-of-service) effluent radiation monitors to assess whether controls were in place to ensure compensatory sampling was performed consistent with the radiological effluent TSs/Offsite Dose Calculation Manual and that those controls were adequate to prevent the release of unmonitored liquid and gaseous effluents.

The inspectors determined whether the facility was routinely relying on the use of compensatory sampling in lieu of adequate system maintenance, based on the frequency of compensatory sampling since the last inspection.

The inspectors reviewed the results of the inter-laboratory comparison program to evaluate the quality of the radioactive effluent sample analyses, and assessed whether the inter-laboratory comparison program included hard-to-detect isotopes as appropriate.

b. Findings

No findings were identified.

.4 Instrumentation and Equipment (02.04)

Effluent Flow Measuring Instruments

a. Inspection Scope

The inspectors reviewed the methodology the licensee used to determine the effluent stack and vent flow rates to determine if the flow rates were consistent with radiological effluent TSs/Offsite Dose Calculation Manual or Final Safety Analysis Report values, and that differences between assumed and actual stack and vent flow rates did not affect the results of the projected public doses.

b. Findings

No findings were identified.

Air Cleaning Systems

a. Inspection Scope

The inspectors assessed whether surveillance test results since the previous inspection for TS required ventilation effluent discharge systems (high-efficiency particulate air and charcoal filtration), such as the Containment/Auxiliary Building Ventilation System met TS acceptance criteria.

b. Findings

No findings were identified.

.5 Dose Calculations (02.05)

a. Inspection Scope

The inspectors reviewed all significant changes in reported dose values compared to the previous radiological effluent release report (e.g., a factor of five, or increases that approach Appendix I criteria) to evaluate the factors which may have resulted in the change.

The inspectors reviewed radioactive liquid and gaseous waste discharge permits to assess whether the projected doses to members of the public were accurate, and based on representative samples of the discharge path.

Inspectors evaluated the methods used to determine the isotopes that were included in the source term to ensure all applicable radionuclides were included within detectability standards. The review included the current Part 61 analyses to ensure hard-to-detect radionuclides were included in the source term.

The inspectors reviewed changes in the licensee's offsite dose calculations since the last inspection to evaluate whether changes were consistent with the Offsite Dose Calculation Manual and Regulatory Guide 1.109. Inspectors reviewed meteorological dispersion and deposition factors used in the Offsite Dose Calculation Manual and effluent dose calculations to evaluate whether appropriate factors were being used for public dose calculations.

The inspectors reviewed the latest Land Use Census to assess whether changes (e.g., significant increases or decreases to population in the plant environs, changes in critical exposure pathways, the location of nearest member of the public or critical receptor, etc.) had been factored into the dose calculations.

For the releases reviewed above, the inspectors evaluated whether the calculated doses (monthly, quarterly, and annual dose) were within the 10 CFR Part 50, Appendix I, and TS dose criteria.

The inspectors reviewed, as available, records of any abnormal gaseous or liquid tank discharges (e.g., discharges resulting from misaligned valves, valve leak-by, etc.) to ensure the abnormal discharge was monitored by the discharge point effluent monitor. Discharges made with inoperable effluent radiation monitors, or unmonitored leakages were reviewed to ensure that an evaluation was made of the discharge to satisfy 10 CFR 20.1501, so as to account for the source term and projected doses to the public.

b. Findings

No findings were identified.

.6 Groundwater Protection Initiative Implementation (02.06)

a. Inspection Scope

The inspectors reviewed monitoring results of the Groundwater Protection Initiative to determine if the licensee had implemented its program as intended, and to identify any anomalous results. For anomalous results or missed samples, the inspectors assessed whether the licensee had identified and addressed deficiencies through its CAP.

The inspectors reviewed identified leakage or spill events and entries made into 10 CFR 50.75 (g) records. The inspectors reviewed evaluations of leaks or spills and reviewed any remediation actions taken for effectiveness. The inspectors reviewed on-site contamination events involving contamination of ground water and assessed whether the source of the leak or spill was identified and mitigated.

For unmonitored spills, leaks, or unexpected liquid or gaseous discharges, the inspectors assessed whether an evaluation was performed to determine the type and amount of radioactive material that was discharged by:

- Assessing whether sufficient radiological surveys were performed to evaluate the extent of the contamination and the radiological source term and assessing whether a survey/evaluation had been performed to include consideration of hard-to-detect radionuclides; and
- Determining whether the licensee completed offsite notifications, as provided in its Groundwater Protection Initiative implementing procedures.

The inspectors reviewed the evaluation of discharges from onsite surface water bodies that contained or potentially contained radioactivity, and the potential for ground water leakage from these onsite surface water bodies. The inspectors assessed whether the licensee was properly accounting for discharges from these surface water bodies as part of their Effluent Release Reports.

The inspectors assessed whether on-site ground water sample results and a description of any significant on-site leaks/spills into ground water for each calendar year were documented in the Annual Radiological Environmental Operating Report for the Radiological Environmental Monitoring Program or the Annual Radiological Effluent Release Report for the Radiological Effluent TSs.

For significant, new effluent discharge points (such as significant or continuing leakage to ground water that continued to impact the environment if not remediated), the inspectors evaluated whether the offsite dose calculation manual was updated to include the new release point.

b. Findings

No findings were identified.

.7 Problem Identification and Resolution (02.07)

a. Inspection Scope

The inspectors assessed whether problems associated with the Effluent Monitoring and Control Program were being identified by the licensee at an appropriate threshold, and were properly addressed for resolution in the licensee's CAP. In addition, they evaluated the appropriateness of the corrective actions for a selected sample of problems documented by the licensee involving radiation monitoring and exposure controls.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications performance indicator for Units 1 and 2 for the period of the first quarter of 2014 to the first quarter of 2015. To determine the accuracy of the performance indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, CAPs, event reports and NRC Integrated IRs for the period provided above to validate the accuracy of the submittals. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned scrams with complications samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index (MSPI)—High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI—High Pressure Injection Systems performance indicator for the period from the second quarter of 2014 through the first quarter of 2015. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, CAPs, MSPI derivation reports, event reports, and NRC Integrated IRs for the period listed above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index—Heat Removal Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI—Heat Removal Systems performance indicator for the period from the second quarter of 2014 through the first quarter of 2015. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, CAPs, event reports, MSPI derivation reports, and NRC Integrated IRs for the period listed above to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's CAP database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

a. Inspection Scope

As part of the various baseline IPs discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

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

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

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

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

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of January 1 through June 30, 2015, although some examples expanded beyond those dates where the scope of the trend warranted.

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

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

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: Review of Direct Current System Margin Issues

a. Inspection Scope

On April 9, 2015, the licensee initiated a CAP identifying a non-conservative TS for the battery chargers. The licensee had previously identified that the instrument inverters could potentially load on to the respective battery following a loss of off-site power (LOOP). As a result of this condition, the licensee found that TS Surveillance Requirement (SR) 3.8.4.2 was non-conservative because it did not account for the additional loads related to the instrument inverters. As a result of this CAP, compensatory measures were taken to remove non-essential loads from the direct current (DC) system to bring the total loading of the battery charger into an operable condition.

The inspectors reviewed the operability and design function of the DC systems. The inspectors reviewed corrective action documents, design calculations, OPRs, WOs, and engineering changes (ECs) regarding the DC systems. The inspectors also discussed the DC systems issues with engineering and licensing personnel. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

(1) #12 Battery Charger Design Control

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," for the failure to ensure the design requirements of the #12 battery charger were maintained. Specifically, the licensee failed to address the impact that previously identified additional loads had on the design capacity of the battery charger.

Description: Prairie Island has four battery chargers and one portable battery charger. Each battery charger was sized/designed to recharge its associated battery from a partially discharged voltage of 105 volts DC within 24 hours while carrying its normal load. On May 2, 2010, design calculation ENG-EE-002, "12 Battery Charger Sizing Calculation," was revised and defined the normal loads on the DC distribution system to be 201.41 amperes (A). The normal loads were calculated to take into account expected loads for a design basis accident (DBA) concurrent with LOOP. The calculation identified that the minimum size battery charger needed to recharge a depleted #12 battery in 24 hours while carrying the normal DC system loads would have to be greater than 279.69 A.

On February 9, 2011, the licensee wrote CAP 1270104 after identifying a non-conservative assumption in the Unit 1 battery calculations. The CAP identified that during EDG load sequencing, the normal AC input breaker to the instrument inverters would unexpectedly open (trip). When the inverter's AC input breaker tripped, the power supplied to the inverter automatically switched to DC to provide power to other safety-related loads without interruption. This caused the inverters to be a load on the DC system. This additional load had not been accounted for in the battery sizing or battery charger sizing calculations. As a result, the licensee could not show that the battery charger would be able to supply power to its normal loads and recharge its associated battery from a partially discharged state within 24 hours.

The additional loads on the system included loads from the #12 inverter, #14 inverter, and #18 inverter. This resulted in additional loads on the DC system of 33 A, 35 A, and 19 A, respectively. The licensee also identified that the battery charger sizing calculation had not taken into account loading from EC 25251 which installed DC powered solenoid valves on various plant equipment. The additional load from EC 25251 was 10.14 A. Therefore, the additional loads would increase the normal loads on the #12 battery charger to 298.14 A. The current battery charger had a nominal rated DC output of 400 A with an adjustable current limit set under 315 A at 130 volts DC. With the additional loads on the DC system and the #12 battery charger set to 315 A, the #12 battery charger would remain operable to provide DC power to the normal loads; however, the time to recharge the #12 battery would exceed the required 24 hours.

The inspectors reviewed the above history of issues and were concerned that the licensee had not addressed the design requirements of the #12 battery charger since the licensee originally identified the concerns going back to 2011.

Additionally, on April 9, 2015, the licensee wrote CAP 1473569 to document a non-conservative TS regarding the battery chargers. Specifically, the licensee identified that the battery chargers could not meet TS SR 3.8.4.2 due to the additional loading on the DC systems discussed above. The TS SR 3.8.4.2 required the licensee to demonstrate that the battery chargers would perform their safety function during a design basis event. As a result of this CAP, the licensee implemented compensatory measures to remove non-essential lighting loads from the DC systems. This load reduction brought the total battery charger loading to within its design capacity.

Analysis: The inspectors determined that the failure to maintain the design basis for the battery charger was contrary to 10 CFR 50 Part 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency. Specifically, the additional loads that could be placed on the battery charger were not accounted for in the design and exceeded the existing design capacity of the battery charger.

This finding was more than minor because it is associated with the Mitigating Systems cornerstone attribute of design control and affected the associated cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee failed to account for the additional load of the inverters on the #12 battery charger. This additional load exceeded the battery charger's design capacity and as a result, the licensee could not demonstrate that the #12 battery charger would be capable of responding to initiating events to prevent undesirable consequences.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," issued June 19, 2012, and Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," issued June 19, 2012, the inspectors answered "Yes" to Question 2 of the Mitigating SSCs and Functionality screening questions, because the finding represented a loss of function of the #12 battery charger. Thus the inspectors consulted the regional senior reactor analyst (SRA) for additional assistance. The SRA reviewed the inspection finding and concluded that the inability of the #12 battery charger to recharge the battery within 24 hours would not impact the overall DC power system function of providing DC power to plant equipment during normal operation and in response to postulated initiating events. Therefore, the probabilistic risk assessment (PRA) function of the DC system was not affected. As a result, the finding was determined to be of very low safety significance (Green).

No cross-cutting aspect was assigned to this finding as the actions taken in 2011 were not reflective of current performance.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program.

Contrary to the above, from May 2010 until April 2015, the licensee failed to ensure the adequacy of the safety-related battery charger design. Specifically, the licensee failed to address the impact of additional identified loads on the design capacity of the battery chargers. These additional loads resulted in the #12 battery charger exceeding its design capacity. Because this violation was of very low safety significance and was entered into the licensee's CAP as CAP 1477898, this violation is being treated as an

NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015002–01, #12 Battery Charger Design Control)**.

(2) Failure to Correct #12 Battery Nonconformance

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to promptly correct a condition adverse to quality. Specifically, the licensee failed to correct a non-conforming condition for the #12 battery that was discovered in February 2011.

Description: On February 9, 2011, the licensee initiated CAP 1270104 to document a non-conservative assumption in the Unit 1 battery calculations. The CAP identified that during EDG load sequencing, the EDG experienced a voltage overshoot. Consequently, the normal AC input breaker to the instrument inverters would trip due to actuation of the inverter protection circuit. When the inverter's AC input breaker tripped, the inverter's power supply automatically switched to DC power to provide power to other safety-related loads without interruption; thereby, causing the inverters to be a load on the DC system. This additional load had not been accounted for in the battery sizing or battery charger sizing calculations.

The required size of the battery is based on a capacity factor of 80 percent in accordance with IEEE Standard 485. With the additional inverter loads on the respective battery, the licensee found that a minimum capacity factor of 88.5 percent was needed to ensure that the #12 battery would be able to perform its safety function. The inspectors and the licensee reviewed surveillances performed since the #12 battery was installed in 2002 to verify the actual battery capacity factor. The surveillance results showed that the #12 battery capacity factor had remained greater than 100 percent. Therefore, the #12 battery was declared operable but non-conforming.

The licensee initially intended to correct the EDG voltage overshoot via analysis and incorporate the instrument inverter loads into the battery design calculations 91-02-11 and 91-02-12. An action item (Assign No. 1270104-05) was created to track this issue with an original due date of April 27, 2012. However, this action item had been extended six separate times and was due June 26, 2015. No physical actions occurred to ensure that the #12 battery was returned to its original design.

Additionally, an action item (Assign No. 1270104-02) was created in February 2011 to address the non-conforming battery with an original due date of September 15, 2011. The action item due date was then extended seven separate times and was currently due July 15, 2015. Again, no physical actions occurred to return the #12 battery design to its original configuration.

The inspectors reviewed the above history of issues and were concerned that the licensee had not appropriately addressed the non-conformance of the #12 battery since the licensee originally identified the concerns going back to 2011.

On April 9, 2015, CAP 1473569 was written identifying a non-conservative TS regarding of the battery chargers. As a result of this CAP, compensatory measures were taken to remove non-essential lighting loads from the battery to bring the total loading of the battery charger into an acceptable range. This compensatory action also brought the #12 battery under the 80 percent capacity factor. Discussions with the licensee identified that the compensatory measures were expected to become permanent modifications. As a result, the licensee planned to return the #12 battery design to a conforming condition once the modification paperwork was processed.

Analysis: The inspectors determined that the failure to correct a non-conforming condition in a timely manner was contrary to 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," and was a performance deficiency. Specifically, the licensee failed to take any corrective action to restore the #12 battery to a conforming design since entering the issue into their CAP in February 2011.

The finding was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Equipment Performance and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee did not take timely corrective actions to restore the #12 battery to a fully operable status. Additionally, no corrective action was taken to correct the occurrence of the inverters' AC circuit breakers tripping of the normal load and becoming an additional load on to the DC system; thereby, causing the battery to be non-conforming.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," issued June 19, 2012, and Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, "Mitigating Systems Screening Questions," issued June 19, 2012, the inspectors answered "No" to all of the questions. The inspectors confirmed that the finding did not result in a loss of operability or functionality per IMC 0326, "Operability Determination & Functionality Assessments for Conditions Adverse to Quality or Safety," since the capacity of the battery had been tested above the 88.5 percent capacity factor as identified in battery calculation and evaluation. Therefore, this finding was of very low safety significance (Green).

The inspectors determined the finding was cross-cutting in the Problem, Identification and Resolution, Resolution area because of the licensee's failure to implement effective corrective actions to restore operability of the #12 battery. [P.3]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected.

Contrary to the above, from February 2011 to April 2015, the license failed to promptly correct a condition adverse to quality. Specifically, the licensee failed to perform corrective actions to restore the safety-related #12 battery to conform to the specified design. Because this violation was of very low safety significance and was entered into the licensee's CAP as CR 1478105, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015002–02; Failure to Correct #12 Battery Nonconformance)**.

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

.1 Unit 2 Manual Reactor Trip Following Lockout of the 21 Feedwater Pump

a. Inspection Scope

On April 3, 2015, operations personnel inserted a Unit 2 manual reactor trip after experiencing an unexpected loss of the 21 feedwater pump. The inspectors responded to the control room and monitored the operator actions taken to address the event. The inspectors also reviewed the procedures used during this event to determine whether the control room operators responded properly. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified regarding the operators response to this event. Additional details regarding the cause of the feedwater pump lockout are contained in Section 4OA3.7 of this report.

.2 Unit 1 Manual Reactor Trip Following Lockout of the 11 Condensate Pump

a. Inspection Scope

On May 31, 2015, operations personnel inserted a Unit 1 manual reactor trip after experiencing an unexpected loss of the 11 condensate pump. The inspectors responded to the control room and monitored the operator actions taken to address the event. The inspectors also reviewed maintenance activities performed to determine the cause of the condensate pump lockout. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified regarding the operators response to this event. The licensee’s causal evaluation for the condensate pump was ongoing at the conclusion of the inspection. The inspectors planned to review the causal evaluation results following the receipt of LER 05000282/2015–004–00 in July.

.3 Unit 2 Automatic Reactor Trip due to Low Turbine Oil Pressure

a. Inspection Scope

On June 7, 2015, operations personnel experienced an automatic trip of the Unit 2 reactor due to a low turbine oil pressure condition. The inspectors responded to the control room and monitored the licensee’s actions to address the event. The inspectors also discussed the performance of the turbine oil system with operations, engineering and maintenance personnel to determine whether any previous performance problems had been identified. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified regarding the operators response to this event. The licensee's causal evaluation was ongoing at the conclusion of the inspection. The inspectors planned to review the causal evaluation results following the receipt of LER 05000306/2015–003–00 in August of 2015.

.4 (Closed) LER 05000282/2014–004–00: Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit

a. Inspection Scope

On August 8, 2014, the licensee identified that the control circuits for the Unit 1 and Unit 2 emergency bearing oil pumps were not properly fuse protected. As a result, an overload within the oil pump's control circuitry could result in a fire that could propagate to multiple fire areas and affect equipment needed to shut down the plant. The inspectors reviewed the licensee's corrective action documents to determine why this issue occurred. The inspectors also reviewed the licensee's compensatory measures to determine whether the actions met the licensee's fire protection program requirements. Documents reviewed are listed in the Attachment to this report. This LER is closed.

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

b. Findings

Introduction: The inspectors identified a Severity Level (SL) IV NCV of 10 CFR 50.72(b)(3)(ii)(B) due to the licensee's failure to report an unanalyzed condition within eight hours of discovery. Specifically, the lack of fuse protection for the emergency bearing oil pump control circuitry created an unanalyzed condition due to the potential for a fire that impacted the licensee's safe shutdown capabilities.

Description: On August 8, 2014, the licensee identified that original design of the Unit 1 and Unit 2 control circuitry for the emergency bearing oil pumps failed to contain adequate fuse protection to ensure that a cable fault would not result in a subsequent fire. If a fire occurred, it could have spread to multiple fire areas and challenged the licensee's ability to perform safe shutdown activities in the turbine and auxiliary buildings. The licensee initiated CAP 1442220 to document this issue and determined that the condition was not reportable to the NRC because fire watches had been previously established in the portions of the turbine and auxiliary buildings containing emergency bearing oil pump cables.

As part of daily CAP document reviews, the inspectors noted the licensee's reportability conclusion within CAP 1442220 and were concerned that the licensee's reporting decision was incorrect. Specifically, a potential fire due to the lack of fuse protection for the emergency bearing oil pump control circuitry, and the resultant impact on safe shutdown capability resulted in an unanalyzed condition that significantly degraded plant safety.

On August 11, 2014, the inspectors discussed their concern with the licensee. The licensee stated that the issue described in CAP 1442220 was not initially reported because of previously established fire watches that would have been able to identify a fire prior to the fire significantly degrading plant safety. The inspectors discussed the licensee's statements with staff from the NRC's Office of Nuclear Reactor Regulation (NRR). The NRR staff informed the inspectors that the licensee's statements were incorrect based on information from the Statements of Consideration for changes to 10 CFR 50.72 contained on Page 63776 of the Federal Register, Volume 65, Number 207, dated October 25, 2000. This information specifically stated that this type of fire protection issue was required to be reported as an unanalyzed condition that significantly degraded plant safety regardless of whether fire watches had been previously implemented.

The inspectors shared the Federal Register information with the licensee and the licensee documented the inspector's concern within CAP 1442883. The licensee subsequently reported the unanalyzed condition to the NRC on August 13, 2014.

Analysis: The inspectors determined that the failure to submit a report required by 10 CFR 50.72 for the unanalyzed condition described above was a performance deficiency. The inspectors determined that this issue had the potential to impact the regulatory process based, in part, on the information that 10 CFR 50.72 reporting serves. Since the issue impacted the regulatory process, it was dispositioned through the Traditional Enforcement process. The inspectors determined that this issue was a SL IV violation based on Example 6.9.d.9 in the NRC Enforcement Policy. Example 6.9.d.9 specifically states, "A licensee fails to make a report required by 10 CFR 50.72 or 10 CFR 50.73."

This violation was also associated with a finding for which the NRC has exercised enforcement discretion (see Section 4OA7 for further details).

Because the licensee identified the technical issue as part of their National Fire Protection Association (NFPA)–805 transition process, and no additional or separate NRC-identified or self-revealed more-than-minor Reactor Oversight Process (ROP) findings were noted, there was no cross-cutting aspect associated with this violation.

Enforcement: Title 10 CFR 50.72(b)(3), "Eight-hour reports," requires, in part, that "If not reported under paragraphs (a), (b)(1) or (b)(2) of this section, the licensee shall notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the following:…(ii) Any event or condition that results in:…(B) The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety."

Contrary to the above, on August 8, 2014, the licensee failed to report the discovery of an unanalyzed condition associated with inadequate fuse protection of the emergency bearing oil pumps within 8 hours. Corrective actions for this issue included reporting the condition on August 13, 2014, revising procedures, and reviewing other fire protection related issues to ensure that they had been properly reported. Because this issue was entered into the licensee's CAP as CAP 1442883, it is being treated as a SL IV NCV consistent with Section 2.3.2 of the NRC Enforcement Policy **(SL IV NCV 05000282/2015002–03; 05000306/2015002–03, Failure to Make an 8-Hour Report Required by 10 CFR 50.72(b)(3)(ii)(B)).**

.5 (Closed) LER 05000282/2014–004–01: Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit

a. Inspection Scope

On March 31, 2015, the licensee submitted a supplement to LER 05000282/2014–004–00 to clarify why the reported condition occurred, add details to the safety significance section of the report, and modify the corrective actions. The inspectors reviewed this information to ensure that it did not change the inspectors' assessment or the regulatory significance documented in Section 4OA7 of this report.

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

b. Findings

The inspectors determined that the information provided in the LER supplement did not change their assessment or the regulatory significance of this issue. See Section 4OA7 of this report for additional details.

.6 (Closed) LER 05000282/2014–006–00: Missing Fire Barrier

a. Inspection Scope

The inspectors reviewed information provided by the licensee regarding the identification of two missing fire barriers. One of the fire barriers was located within the auxiliary building. The other missing barrier was located inside the auxiliary feedwater pump room. During the inspection, the inspectors reviewed the fire protection program documents to determine the safe shutdown equipment potentially impacted by each issue, the fire detection/suppression equipment available in each fire area impacted and to evaluate whether one train of safe shutdown equipment remained free from fire damage should a credible fire scenario occur. The inspectors discussed the missing barriers with the licensee's fire protection engineers to gain an understanding credible fire scenarios present in each fire area of concern and the corrective actions to resolve each deficiency. Documents reviewed are listed in the Attachment to this report. This LER is closed.

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

b. Findings

Introduction: Two findings of very low safety significance, one NCV and one NCV for which the NRC exercised enforcement discretion were identified during the review of this LER. The inspectors determined that the finding and NCV associated with the missing fire barrier in the auxiliary building was best characterized as a licensee identified finding and violation. As a result, the inspectors documented information regarding this issue in Section 4OA7 of this IR. An inspector identified finding of very low safety significance and an NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified on October 13, 2014, due to the failure to ensure the design requirements of the fire protection program were maintained. Specifically, the licensee had not ensured that Group E pressurizer heaters would continue to operate following a fire in Fire Area 32 (the Unit 1 side of the auxiliary feedwater pump room). As a result, the licensee was unable to ensure that the Unit 1 reactor would be able to achieve and maintain a cold shutdown condition following a fire in this area.

Description: As discussed in Section 4OA3.1 of this report, the NRC identified that the licensee had not reported an unanalyzed condition within eight hours as required by 10 CFR 50.72. Following this discovery, the licensee conducted an extent of condition review to determine whether previously identified fire protection issues were properly reported. The licensee determined that an auxiliary building missing fire barrier issue identified on October 13, 2011, was not properly reported when it occurred. Although this condition has been corrected, the licensee reported this issue to the NRC on September 19, 2014. The enforcement action regarding the missing fire barrier issue is discussed in Section 4OA7 of this report.

During a subsequent field validation of cables that powered equipment following fires in specific plant areas, the licensee identified the Group E pressurizer heater cables were not properly protected to ensure that they would remain operational following a fire in Fire Area 32. As a result, the licensee's ability to place the Unit 1 reactor in a cold shutdown condition following a fire in this area was challenged. The licensee initiated CAP 1450681 to document this issue.

The inspectors reviewed the licensee's apparent cause evaluation report for CAP 1450681 and determined that, prior to 2000, the licensee's fire protection safe shutdown analysis did not credit the use of the Group E pressurizer heaters for fires occurring in Fire Area 32. In May 2003, the licensee implemented Design Change 00SI01 to change the safety injection pump safe shutdown credited water supply from the boric acid storage tank to the refueling water storage tank. This was a safety-related modification covered by 10 CFR 50, Appendix B. Although this change was reviewed by fire protection personnel, the review failed to identify the need to update calculation ENG–ME–048, "Appendix R – Reactor Coolant System Inventory Control with a Safety Injection Pump." In addition, the licensee had not identified that the change in water supplies also required the use of pressurizer heaters to ensure that reactor coolant system sub-cooling margin was maintained. The licensee also discovered six additional opportunities to have identified the inadequately protected Group E pressurizer heaters. These opportunities occurred between April 2005 and May 2008. The inspectors reviewed the circumstances surrounding each of these examples and found that the lack of appropriate protection for the Group E pressurizer cables went unrecognized because the licensee had not verified that the actual Unit 1 pressurizer heater cable configuration matched the cable configuration assumptions contained in calculation ENG–ME–048.

Analysis: The inspectors determined that the failure to ensure the design requirements of the fire protection program were maintained was a performance deficiency that was within the licensee's ability to foresee and correct. Specifically, the licensee failed to ensure that the Group E pressurizer heaters were protected from fire impacts and would remain operational following a fire in Fire Area 32 because the actual Group E pressurizer heater cable configuration was not validated to ensure it matched the fire protection safe shutdown analysis assumptions.

The inspectors used the guidance contained in IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, and determined that the failure to ensure that the Group E pressurizer heaters would remain operational following a fire in Fire Area 32 was more than minor because it was associated with the Protection from External Factors attribute of the Mitigating Systems cornerstone. The finding also impacted the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors utilized IMC 0609, Attachment 4, “Initial Characterization of Findings,” dated June 19, 2012, and determined that this finding was best assessed for safety significance by using IMC 0609, Appendix F, “Fire Protection Significance Determination Process.” The inspectors used IMC 0609, Appendix F, Attachment 1, “Fire Protection SDP Phase 1 Worksheet,” dated September 20, 2013, and assigned a Post-Fire Safe Shutdown fire inspection finding category to the issue per Step 1.2. Based upon the information contained in Step 1.3 of IMC 0609, Appendix F, Attachment 1, the finding was determined to be of very low safety significance because any fire related damage to the Group E pressurizer heater cables did not impact the licensee’s ability to reach and maintain a safe shutdown condition (either hot or cold).

No cross-cutting aspect was assigned to this issue since the missed opportunities to identify this issue occurred more than three years ago and were not reflective of current performance.

Enforcement: Criterion III of 10 CFR Part 50, Appendix B, requires, in part, that the applicable regulatory requirements and design basis are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, between May 30, 2003, and October 13, 2014, the licensee failed to ensure regulatory requirements regarding the ability of equipment to remain operational following a fire were correctly translated into the fire protection program’s safe shutdown analysis and Calculation ENG–ME–048. Specifically, the licensee failed to ensure that the actual cable configuration for the Group E pressurizer heaters was adequate such that the heaters would remain operational and support placing Unit 1 in a cold shutdown condition following a fire in Fire Area 32. Corrective actions for this issue included developing a post-fire pressurizer heater cable repair strategy as allowed by 10 CFR Part 50, Appendix R, “Fire Protection.” Because this violation was of very low safety significance and it was entered into the licensee’s CAP as CAP 1450681, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000282/2015002–04, Design Control Measures not Implemented to Ensure Group E Pressurizer Heaters Remain Operational Post-Fire)**.

.7 (Closed) LER 05000306/2015–002–00: 21 Feedwater Pump Lockout, Unit 2 Reactor Trip due to Pressure Switch Failure

a. Inspection Scope

On April 3, 2015, operations personnel manually tripped the Unit 2 reactor following the unexpected lockout of the 21 feedwater pump. The inspectors reviewed the licensee’s immediate actions following the reactor trip and the licensee’s corrective action documents to determine the cause of the feedwater pump lockout. The inspectors also discussed the performance of the 21 feedwater pump with engineering personnel. This LER is closed.

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

b. Findings

No findings were identified. The licensee determined that the 21 feedwater pump locked out due to pressure switch internal failure. The inspectors reviewed previous operating experience on this type of pressure switch, the performance of the specific pressure switch and the licensee's pressure switch maintenance practices and concluded that the internal failure was not within the licensee's ability to foresee and correct. Therefore, no finding or violation of NRC requirements was identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 24, 2015, the inspectors presented the inspection results to Mr. K. Davison, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the areas of radiological hazard assessment and exposure controls; and radioactive gaseous and liquid effluent treatment with Mr. K. Davison, Site Vice President, on April 17, 2015.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee. The NRC is not taking enforcement action for these violations because they meet the criteria of the NRC Enforcement Policy, "Interim Enforcement Policy Regarding Enforcement Discretion for Certain Fire Protection Issues (10 CFR 50.48)," as described below:

- Title 10 CFR Part 50, Appendix R, requires, in part, that safe shutdown equipment and systems for each fire area shall be known to be isolated from associated non-safety circuits in the fire area so that hot shorts, open circuits, or shorts to ground in the circuit will not prevent operation of the safe shutdown equipment. The isolation of these associated circuits from the safe shutdown equipment shall be such that a postulated fire involving the associated circuits will not prevent safe shutdown. On August 8, 2014, the licensee identified an Appendix R non-compliance in that the emergency bearing oil pumps were not properly isolated (fuse protected) from safe shutdown equipment, in accordance with 10 CFR Part 50, Appendix R. As a result, an overload condition in the emergency bearing oil pump circuitry could result in a fire that damages other cabling and prevents the licensee from achieving safe shutdown following a fire.

The inspectors reviewed this issue and determined that the improper fuse protection was part of the initial plant design. Specifically, the design philosophy in the late 1960's was to maximize the reliability and availability of the emergency bearing oil pumps to protect the main turbines. The potential impact that this design philosophy had on fire protection of safe shutdown equipment was also not recognized as 10 CFR 50, Appendix R, did not exist until the early 1980's. The licensee documented this issue in CAP 1442220. The licensee also implemented hourly fire watches in the impacted fire areas to ensure that any potential fires were identified prior to it impacting safe shutdown capability.

Section 9.1 of the NRC Enforcement Policy allows the NRC to exercise enforcement discretion for certain fire protection related non-compliances identified as a result of a licensee's transition to the new risk-informed, performance-based fire protection approach included in 10 CFR 50.48(c) and for certain existing non-compliances that reasonably may be resolved by compliance with 10 CFR 50.48(c) as long as certain criteria are met. This risk-informed, performance-based approach is referred to as NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." In 2005, the licensee submitted a letter of intent to transition to 10 CFR 50.48(c). This licensee submitted a license amendment request to the NRC for review and approval in September 2012.

The inspectors reviewed the remaining criteria included in Section 9.1 of the NRC Enforcement Policy and concluded that the licensee had met the criteria. Specifically, the licensee entered the noncompliance into the CAP as CAP 1442220, implemented compensatory fire watches in the area and the noncompliance was not willful. In addition, this issue would not have been identified under normal surveillance or quality assurance activities. Lastly, a regional SRA reviewed an analysis performed by the licensee to show that the risk of the condition was less than high safety significance (i.e., less than red). The licensee identified the cable routing for the six cables of concern (three for each unit) and the fire scenarios where an initial fire could cause a secondary fire in a separate fire area due to the inadequate fusing of the emergency bearing oil pumps. The licensee's evaluation assumed that a secondary fire would be limited to the cable tray that contained the faulted cable and would not propagate beyond that tray. The licensee cited NFPA 805 FAQ–13–005, "Close-out of Fire Probabilistic Risk Assessment Frequently Asked Question 13–005 on Cable Fires Special Cases: Self-Ignited and Caused by Welding and Cutting," that provided similar guidance for self-ignited cable fires as the basis for the assumption. The SRA consulted with NRC Headquarters staff and concluded that the FAQ guidance did not specifically apply to cable fires resulting from inadequate fusing. However, there currently is no available method for estimating the likelihood and extent of a secondary cable fire caused by inadequate fusing. Given the lack of an acceptable method, the SRA also performed a walk down of the control cable routing to observe the potential for secondary fires to impact additional targets. In all cases, there did not appear to be a significant potential for a secondary fire to damage additional targets beyond the cable tray of interest. The licensee provided other reasons why secondary fire damage would be limited, such as existing fire detection and suppression systems and the fact that the cables are thermoset rather than thermoplastic material. The SRA determined that the likelihood of significant secondary fire spread for these particular scenarios was low. The licensee also determined that some scenarios did not impact any unique targets. For those scenarios, there was no change in risk due to the inadequate fusing. For scenarios that did have the potential for additional target damage from a secondary fire, the licensee calculated the change in risk of this condition. The change in risk was determined to be less than 1E–4/yr. The dominant fire scenarios involved a fire starting in the fire area 18 with a secondary fire propagating to either Fire Area 58, 31, or 32.

Because each of the criteria listed in Section 9.1 of the NRC Enforcement Policy was met, the NRC concluded that enforcement discretion should be granted for this issue. No enforcement action will be documented unless the licensee fails to address this non-compliance after completing their transition activities.

- Title 10 CFR Part 50, Appendix R, requires, in part, that fire protection features shall be provided for SSCs important to safe shutdown. These features shall be capable of limiting fire damage so that one train of systems needed to achieve and maintain hot shutdown from either the control room or emergency control station(s) is free of fire damage and that equipment needed to achieve and maintain cold shutdown can be repaired within 72 hours. In addition, where cables and equipment located outside of containment could prevent equipment operation or cause miss-operation due to hot shorts, open circuits or shorts to ground of redundant trains of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, separation of cables and equipment must be maintained through the use of a fire barrier with a three-hour rating to ensure one train of redundant equipment remains free of fire damage. On October 13, 2011, the licensee failed to provide fire protection features for SSCs important to safe shutdown that limited fire damage such that one train of systems remained free from fire damage, in accordance with 10CFR Part 50, Appendix R. Specifically, the licensee identified that Rodofoam material present in the auxiliary building seismic joint seals failed to provide a three hour fire barrier to ensure that one train of redundant safe shutdown equipment remained free from fire damage following a fire due to Rodofoam being a combustible material.

The inspectors reviewed this issue and determined that the Rodofoam material was part of the initial plant design. In addition, these seals were not identified as fire penetration seals. As a result, the seals were not considered to be part of the fire protection program. Once the Rodofoam material was found, the licensee initiated periodic fire watches in the impacted areas and initiated CAP 1308129. The fire watches remained in place until the Rodofoam seals were replaced with a non-combustible seal material.

The inspectors determined that the failure to ensure that equipment was protected from fire, such that one train of equipment remained free from fire damage was a performance deficiency and a violation of 10 CFR 50, Appendix R. However, Section 9.1 of the NRC Enforcement Policy allows the NRC to exercise enforcement discretion for certain fire protection related non-compliances identified as a result of a licensee's transition to the new risk-informed, performance-based fire protection approach included in 10 CFR 50.48(c) and for certain existing non-compliances that reasonably may be resolved by compliance with 10 CFR 50.48(c) as long as certain criteria are met. This risk-informed, performance-based approach is referred to as NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants." In 2005, the licensee began the process of transitioning from the requirements of 10 CFR 50, Appendix R to NFPA 805. This process included submitting a licensing amendment to the NRC for review and approval in September 2012.

The inspectors reviewed the criteria included in Section 9.1 of the NRC Enforcement Policy and concluded that the licensee had met the criteria for enforcement discretion. Specifically, the licensee entered the noncompliance into the CAP as CAP 1308129 and implemented compensatory fire watches in the area until the seals were replaced with an appropriate material. Additionally, this issue would not have been identified under normal surveillance or QA activities. This issue was not willful since the seismic gap seals were installed prior to the development of the fire protection requirements. The inspectors evaluated the significance of this finding in accordance with IMC 0609, "Significance Determination Process," Attachment 4, "Initial Characterization of Finding," dated June 19, 2012, and determined that the finding affected the Mitigating System cornerstone. The inspectors determined that the finding degraded fire protection defense-in-depth strategies so IMC 0609, Appendix F, "Fire Protection Significance Determination Process," dated September 20, 2013, was used to determine the safety significance. The inspectors concluded that this issue was of very low safety significance because the credited safe shutdown equipment was located more than ten feet horizontally or vertically away from the flammable seal material. As a result, a credible fire on either side of the flammable seal material would not result in damage to the redundant safe shutdown equipment on the other side. Because there were no redundant cables or equipment penetrating the seal area, the inspectors concluded that hot gases, which could penetrate the seal, would cool and disperse, such that redundant cables and equipment would not have been damaged. Therefore, no credible fire could affect the ability to achieve and maintain safe shutdown.

Because each of the criteria listed in Section 9.1 of the NRC Enforcement Policy was met, the NRC concluded that enforcement discretion should be granted for this issue. No enforcement action will be documented unless the licensee fails to address this non-compliance after completing their transition activities.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

K. Davison, Site Vice President
S. Sharp, Director Site Operations
E. Blondin, Site Engineering Director
J. Ruttar, Plant Manager, acting
D. Barker, Production Planning Manager
J. Boesch, Maintenance Manager
T. Borgen, Training Manager
B. Boyer, Radiation Protection Manager
H. Butterworth, Nuclear Oversight Manager
F. Calia, Business Support Director
B. Carberry, Emergency Planning Manager
J. Corwin, Security Manager
D. Gauger, Chemistry and Environmental Manager
S. Martin, Performance Assessment Manager
M. Pearson, Regulatory Affairs Manager
D. Lapcinski, Operations Manager, acting

NRC

K. Riemer, Chief, Reactor Projects Branch 2
T. Beltz, Project Mananger, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000282/2015002–01	NCV	#12 Battery Charger Design Control (Section 4OA2.4(1))
05000282/2015002–02	NCV	Failure to Correct #12 Battery Nonconformance (Section 4OA2.4(2))
05000282/2015002–03; 05000306/2015002–03:	SLIV	Failure to Make an 8-Hour Report Required by 10 CFR 50.72(b)(3)(ii)(B) (Section 4OA3.4)
05000282/2015002–04	NCV	Design Control Measures not Implemented to Ensure Group E Pressurizer Heaters Remain Operational Post-Fire (Section 4OA3.6)
05000282/2014–004–00	LER	Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
05000282/2014–004–01	LER	Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
05000282/2014–006–00	LER	Missing Fire Barrier
05000306/2015–002–00	LER	21 Feedwater Pump Lockout, Unit 2 Reactor Trip Due to Pressure Switch Failure

Closed

05000282/2015002–01	NCV	#12 Battery Charger Design Control (Section 4OA2.4(1))
05000282/2015002–02	NCV	Failure to Correct #12 Battery Nonconformance (Section 4OA2.4(2))
05000282/2015002–03; 05000306/2015002–03:	SLIV	Failure to Make an 8-Hour Report Required by 10 CFR 50.72(b)(3)(ii)(B) (Section 4OA3.4)
05000282/2015002–04	NCV	Design Control Measures not Implemented to Ensure Group E Pressurizer Heaters Remain Operational Post-Fire (Section 4OA3.6)
05000282/2014–004–00	LER	Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
05000282/2014–004–01	LER	Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
05000282/2014–006–00	LER	Missing Fire Barrier
05000306/2015–002–00	LER	21 Feedwater Pump Lockout, Unit 2 Reactor Trip Due to Pressure Switch Failure

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.

<u>1R01 Adverse Weather Protection</u>

- H24.3; Structures Monitoring Program; Revision 13
- AB-2; Tornado/Severe Thunderstorm/High Winds; Revision 41
- TP 1636; Summer Plant Operation; Revision 31
- PM 3588-1; Site Roof Drain Annual Inspection; Revision 5
- CAP 1483559; Bus 26 Volts Dropped Below 4000 VAC for 2 Seconds
- CAP 1483532; Roof Leak in 122 Inverter Room
- C20.3 AOP12; Grid Voltage or Frequency Disturbances; Revision 6
- C20.3 AOP1; Evaluating System Operating Conditions When Security Analysis is Out of Service; Revision 16
- C20.3; Electrical Power System Security Analysis; Revision 23
- H24.1 Appendix A; Phase 1 Risk Assessment Preparation; Revision 9
- AB-4; Flood; Revision 48

<u>1R04 Equipment Alignment</u>

- OPR 1469407; Unit 2 Diesel Generator Room Ventilation Evaluation; Revision 0
- DBD SYS-38A; Design Bases Document for the EDG System; Revision 7
- 121 MD CLP Isolate and Drain, Fill and Vent; Revision 3

<u>1R05 Fire Protection</u>

- F5 Appendix A; Fire Detection Zone 36; Fire Area 70 (Partial); Revision 8

<u>1R06 Flood Protection</u>

- DBD TOP-05; Design Bases Document for Internal Flooding; Revision 5
- DBD TOP-13; Design Bases Document for Seismic Requirements; Revision 4
- NF-39228-5; D5/D6 Bldg. Fire Protection System Flow Diagram; Revision 76
- CAP 1475977; NRC Question on D5 Protected Equipment
- SP 1293; Inspection of Flood Control Measures; Revision 26
- AB-4; Flood; Revision 48

<u>1R12 Maintenance Effectiveness</u>

- CAP 1482923; U2 NSSS Relay #18 Buzzing and Has Black/Brown Dust Inside
- CAP 1482079; NSSS ANNUNC System Ground
- CAP 1478125; NSSS Annunciator System Ground Alarm
- Prairie Island Maintenance Rule Bases Document; May 27, 2015
- NE-40411 SH 82; NSSS Annunciator Point Schematic Diagram; Revision F
- C47.0; Control Room Annunciators; Revision 25
- CAP 1482654; Multiple U2 NSSS Audible Alarms
- CAP 1394758; Boric Acid Leak on Pipe VC-369-11 Connection

- CAP 1420122; VC-14(a)(1) Issue: Unit 1 VCT Level Indication Instrument
- Function VC-14 (a)(1) Action Plan Development and Action Plan Goal Setting Template; Revision 0
- CAP 1481610; Rack RPI-2 Chattering
- Maintenance Rule (a)(1) Status Report; April 16, 2015

1R13 Maintenance Risk

- Work Week Safety Profiles; Various Weeks
- High Level Work Schedule; Various Weeks

1R15 Operability Evaluations

- American Society of Mechanical Engineers Boiler and Pressure Vessel Code Case N-513-3; Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping Section XI, Division 1; January 26, 2009
- CAP 1484157; Void Identified at Location 2RH-09 and 2RH-26
- CAP 1441572; RWST Seismic Evaluation
- CAP 1441572; RWST Reverse Osmosis Unit Evaluation
- CAP 1483225; Rx Vessel Flange Leak-off High Temp

1R19 Post Maintenance Testing

- CAP 1475374; D6 Loss of Field During Surveillance Testing
- Troubleshooting Plan; D6 Loss of Field
- Work Request 113507; Inspect D5 Cable from Field Excitation Brush Holder
- Procedure GMP SAC-001; D5/D6 Diesel Generator Minor Inspection – Electrical; Revision 7
- WO 450565-02; 21 Aux Bldg M-U Air Discharge Damper PMT
- CAP 1479555; Unit 1 AMSAC Alarm Received During SP 1780
- SP 1780; AMSAC Quarterly Functional Test; Revision 13
- WO 503512-02; 121 MDCLP Discharge Air Vent Pipe PMT
- NF-39216-1; Flow Diagram Cooling Water – Screen House Unit 1 & Unit 2; Revision 88
- CAP 1475159; Pipe Leak on 121 MD CLP Getting Worse
- CAP 1481042; Flushing of Floor Drains in the 121 MDCLP Room
- WO 519462-07; Flush Void at Location 2RH-09 and 2RH-26
- CAP 1481493; AMSAC out of Service but not on EqOOS Summary Page
- CAP 1481597; 11 CD Ground-Wall Insulation Failure
- CAP 1481261; 21 Aux Bldg Air Discharge Damper Closed Limit Switch Requires Adjustment
- WO 522253-01; U1 AMSAC Has Fault Code
- CAP 1482045; VT-2 Exam Not Completed on 121 MDCLP Prior to Calling Available

1R20 Outage

- SP 2319; Rod Position Verification; Revision 24
- CAP 1481305; 15A FW Heater Relief Lifted Following Unit 1 Rx Trip
- CAP 1481307; ERCS Post Trip Report Did Not Generate
- CAP 1481323; Pin Hole Oil Leak on Discharge of 11 Turbine Oil Lift Pump
- CAP 1481394; ODMI on Unit 1 Reactor Startup Timing 1F2904HS
- CAP 1481431; Entered D14.3 AOP1 Due to Oil Leak From 11 Turbine Lift Oil Pump
- CAP 1481850; Residue Buildup on 13 CFCU
- CAP 1481853; Buildup of Residue on 11 CFCU
- CAP 1481297; 11 Condensate Pump Lockout

- CAP 1472846; 21 FW PMP Suction Pressure Failure and Subsequent Manual Reactor Trip
- C47507; Alarm Response Procedure; Revision 36
- B24 Section 2.1; Turbine-Generator Lube Oil Systems; Revision 10
- 1C1.2-M2; Unit 1 Startup to Mode 2; Revision 2
- 1C1.2-M1; Unit 1 Startup to Mode 1; Revision 4
- FIG C1A-1; Estimated Critical Boron Concentration; Revision 19

1R22 Surveillance Testing

- CAP 1473862; SP 1413, Revision 0 Needs Improvement
- 1M-DC-12 PBC; Installation and Removal of 11 Portable Battery Charger to Battery 12; Revision 4
- CAP 1483106; SP 1502 Could Not Be Completed as Scheduled
- CAP 1483375; CV-31381 IST Stroke Time for Open Position was Outside Reference Range
- SP 1305; D2 Diesel Generator Monthly Slow Start Test; Revision 51
- SP 1071.4; Prerequisites to the Containment Vessel Integrated Leakage Rate Test
- C19.10; Containment Airlock Door Control at Shutdown
- V.SPA.15.009; Risk Evaluation for Maintenance and Personal Airlock Inner Door Missed Surveillance; Revision 0

1EP6 Emergency Preparedness Drills

- Simulator Exercise Guide P9114SD-0802; Revision 0

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

- 5AWI 5.3.0; Key and Seal Control; Revision 14
- RPIP 1008; Radiation Protection Key Control; Revision 18
- RPIP 1106; Access Control Procedures; Revision 18
- RPIP 1120; Posting of Restricted Areas; Revision 38

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

- 2013 and 2014; Prairie Island; Land Use Census
- CAP 01396892; H4 Off-Site Dose Calculation Manual Revision 27 LAR
- CAP 1430657; H4 Off-Site Dose Calculation Manual Revision 28 LAR
- CAP 1462795; Snap Shot Self-Assessment; NRC IP 71124.06 Radioactive Gaseous and Liquid Effluent Treatment
- CAP 1464902; MREP Requests 2R-37 A-1 Determination
- CAP 1465931; Error Noted in the 2011 Annual Effluent Release Report
- CAP 1473573; 1F2903CS Lack of Containment Ventilation Challenges Effluent Control
- CY-ADMN-030; Processing Changes to the ODCM; Revision 1
- CY-ENVR-401; Liquid Waste Tank Release Report; Revision 1
- CY-ENVR-502; Containment Release Instruction; Revision 1
- CY-ENVR-506; Determination of Facility-Related Dose Using REMP TLD Results; Revision Draft
- CY-ENVR-512; Gas Decay Tank Release Instruction; Revision 4
- CY-ENVR-513; Effluent Surveillance Sample Collection; Revision 1
- CY-ENVR-623; Effluent Release Offsite Dose Report; Revision 0
- FP-CY-GWPP-01; Fleet Groundwater Protection Program; Revision 2
- FP-CY-ODC-01; Off-Site Dose Calculation Manual Change Process; Revision 0
- H4; Offsite Dose Calculation Manual (ODCM); Revision 29

- H4.2; ODCM Supporting Data; Revision 1
- H39; Ventilation Filter Testing Program; Revision 6
- PM 3557-1-11; 11 Containment Clean-Up Charcoal Filter Replacement (169-121); Revision 10
- Radiation Monitor Out-of-Service History for CY2014; Dated April 2015
- Radioactive Release Permit PIGB2014-291
- Radioactive Release Permit PIGC2014-390
- Radioactive Release Permit PILB2014-293
- Radioactive Release Permit PILC2014-285
- RPIP 1124; Evaluation of Isotopic Mix; Revision 1
- Title 10 CFR 50.59; File Index and Selected Records 2013 and 2014; April 12, 2015
- Title 10 CFR 50.75.g; File Index and Selected Records; April 12, 2015
- Title 10 CFR 61; Analytical Data from Teledyne Brown Engineering Inc. Report; Various Waste Streams (High Level Cartridge Filters; Low Level Cartridge Filters; High Level Bead Resin, Low Level Bead Resin, Dry Active Waste); Various Dates 2014
- Special Ventilation Systems HEPA and Charcoal Filter Testing Data; Selected Records (Auxiliary Building, Main Control Room, Shield Buildings, Spent Fuel Pool, and the Technical Support Center); Various Dates 2013 and 2014

4OA1 Performance Indicator Verification

- Reactor Oversight Program MSPI Basis Document; Prairie Island Nuclear Generating Plant; Revision 18
- CAP 1429025; Collect April 2014 MSPI Data
- CAP 1429981; Collect May 2014 MSPI Data
- CAP 1435318; Collect June 2014 MSPI Data
- CAP 1440209; Third Quarter 2014 MSPI Data
- CAP 1443209; MR Unavailability Data Collection for August 2014
- CAP 1451572; Fourth Quarter 2014 MSPI Data
- CAP 1462331; First Quarter 2015 MSPI Data
- CAP 1475024; Second Quarter 2015 MSPI Data

4OA2 Identification and Resolution of Problems

- Corrective Action Database Adverse Trend Reports; June 22 – 26, 2015
- CAP 01214555; Battery Charger OPR
- CAP 01270104; Non Conservative Assumption in Unit 1 Battery Calcs
- CAP 01468437; 50.59 Screening No. 4960 – 12 BATT CHG Compensatory Measure
- CAP 01473569; Impact of DC Margin Issues on Surveillance Testing Program
- EC 24525; Evaluation of Additional Emergency Light Loads on 12 Battery
- EC 25610; PINGP Evaluation of TS SR 3.8.4.2 Compliance
- EC 25527; Evaluation of Removing Emergency Lighting on 125VDC SR Batteries
- EC 17202; Replacement of Unit 1 Safety Related Battery Chargers (#11 and #12)
- NSPM Calculation No. ENG-EE-001; 11 Battery Charger Sizing Calculation; March 26, 2012
- NSPM Calculation No. ENG-EE-002; 12 Battery Charger Sizing Calculation; March 29, 2012
- NSPM Calculation No. 91-02-12; Battery 12 Calculation; October 3, 2012
- WO 00520782; SP 1413 – 12 Battery Charger Load Test; April 18, 2015
- WO 00520781; SP 1413 – 11 Battery Charger Load Test; April 22, 2015
- WO 00520784; SP 2413 – 22 Battery Charger Load Test; April 29, 2015
- WO 00520783; SP 2413 – 21 Battery Charger Load Test; April 28, 2015

4OA3 Event Followup

- CAP 1308129; Rodofoam Material Suspected in Auxiliary Building Seismic Joint Seals
- CAP 1442220; Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
- CAP 1450681; Missing Fire Barrier within Fire Area 32
- CAP 1447344; Missing Fire Barrier not Reported
- CAP 1450681; Missing Fire Barrier within Fire Area 32
- CAP 1447194; DC Emergency Oil Pump Control Circuit Should Have Been Identified in NFPA 805
- CAP 1442883; 10 CFR 50.72 Report for CAP 1044220 – Fire Barrier Degraded
- CAP 1234661; Automatic Rector Trip due to Turbine Trip
- Federal Register Volume 65, Number 207; October 25, 2000
- Apparent Cause Evaluation 1442220; Lack of Appropriate Fuse Protection for Emergency Oil Pump Control Circuit
- Apparent Cause Evaluation 1447344; Group E Pressurizer Heater Cables Present in Fire Area 32
- USAR; Section 10.3.1 – Fire Protection Program; Revision 34P
- Procedure F5, Appendix E; Fire Protection Safe Shutdown Analysis; Revision 17
- CAP 1234661; Automatic Reactor Trip due to Turbine Trip
- Equipment Causal Evaluation 1472846

LIST OF ACRONYMS USED

10 CFR	Title 10 of the *Code of Federal Regulations*
A	Amperes
AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AMSAC	Anticipated Transient Without Scram Mitigation System Actuation Circuitry
AOP	Abnormal Operating System
ATWS	Anticipated Transient Without Scram
CAP	Corrective Action Program
DBA	Design Basis Analyses
DC	Direct Current
EC	Engineering Change
EDG	Emergency Diesel Generator
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
LER	Licensee Event Report
LOOP	Loss of Off-site Power
MDCLP	Motor-Driven Cooling Water Pump
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OPR	Operability Evaluation
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PRA	Probabilistic Risk Assessment
QA	Quality Assurance
ROP	Reactor Oversight Process
SL	Severity Level
SR	Surveillance Requirement
SRA	Senior Reactor Analyst
SSC	Systems, Structures, and Components
TS	Technical Specification
TSO	Transmission System Operator
USAR	Updated Safety Analysis Report
WO	Work Order

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Sincerely,

/RA/

Kenneth Riemer
Branch 2
Division of Reactor Projects

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

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DOCKET NO. E999/AA-15-611

Dated this 11th day of August 2016

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Jim Erickson

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