January 29, 1999

Mr. M. Wadley
President, Nuclear Generation
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/98023(DRP); 50-306/98023(DRP)

Dear Mr. Wadley:

On January 14, 1999, the NRC completed an inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection.

This inspection period was characterized by several unexpected operational events, caused by equipment failures, personnel errors, and procedure problems. These events included a reactor coolant system leak, a transformer explosion and reactor trip, two periods of reliance on natural circulation cooling, a loss of the operating residual heat removal pump, and an extended period of reliance on steam generator power-operated relief valves for maintaining reactor coolant system temperature. Although operators were required to rapidly evaluate and respond to the events, in all cases, the performance of control room operators was observed to be professional, calm, and correct. The plant was kept in a stable, safe condition during each of the events. Operators also performed two reactor startups without problems.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

Original signed by

Bruce Burgess, Chief
Reactor Projects Branch 7

Docket Nos.: 50-282, 50-306
License Nos.: DPR-42, DPR-60

Enclosure: Inspection Report 50-282/98023(DRP); 50-306/98023(DRP)

cc w/encl: Plant Manager, Prairie Island
State Liaison Officer, State of Minnesota
State Liaison Officer, State of Wisconsin
Tribal Council, Prairie Island Dakota Community

Mr. M. Wadley
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282, 50-306
License Nos:	DPR-42, DPR-60
Report No:	50-282/98023(DRP); 50-306/98023(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	December 4, 1998, through January 14, 1999
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Resident Inspector S. Thomas, Resident Inspector
Approved by:	Bruce Burgess, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Units 1 & 2
Prairie Island Inspection Report 50-282/98023(DRP); 50-306/98023(DRP)

This inspection was performed by the resident inspectors and included aspects of licensee operations, maintenance, engineering, and plant support.

Operations

- Operators demonstrated good control of plant equipment while entering reduced reactor coolant system inventory conditions during the Unit 2 refueling outage. Also, operators responded well to the failure of the Unit 1 auxiliary transformer and maintained control of reactor coolant system temperature by dissipating reactor decay heat using the steam generator power-operated relief valves. (Section O1.1)

- A safeguards bus circuit breaker was mistakenly racked out by an operator and the independent verification failed to identify the error. (Section O1.1)

- One instance of inadequate control room logkeeping was noted during testing of a newly installed diverse scram system. (Section O1.1)

- The material condition of the piping and components associated with the 21 and 22 safety injection accumulators was good. Prompt corrective actions were initiated by the system engineer to correct some minor material discrepancies. (Section O1.2)

- Control room operators took prompt and effective actions to locate, minimize, and quantify an reactor coolant system leak during plant heatup on Unit 2. A reactor operator requested a leak status update that was particularly useful in ensuring all operators and shift management had the most recent information and understood the intended course of action. (Section O1.3)

- Unit 2 reactor startup, approach to criticality, and low power physics testing were performed in a slow, controlled, and deliberate manner. Operators responded appropriately to unexpected turbine speed control responses during initial attempts to parallel the main generator to the grid. The second, successful attempt to parallel to the grid was characterized by good crew communications, attentiveness to plant parameters, and procedural awareness. Subsequent power ascension and return to near full power operations occurred with no discrepancies. (Section O1.4)

- Licensee personnel responded well to the explosion of the 1M station auxiliary transformer and subsequent fire. Control room personnel quickly determined the cause of the reactor trip and took actions to place the reactor plant in a safe and stable condition. Restoration actions were comprehensive and adequately addressed short-term and long-term equipment issues. (Section O1.5)

- Unit 1 reactor startup, approach to criticality, and power ascension following the Unit 1 station auxiliary transformer explosion were performed in an attentive, well-controlled manner. (Section O1.6)

- The licensee's cold weather preparations were adequate to protect the selected areas of the plant from severe winter weather. (Section O1.7)

- Operators and licensee procedures did not use the same definition of the term "hot shutdown" as that in the Technical Specifications. (Section O3.1)

Maintenance

- Most maintenance and surveillance activities observed were performed properly. No discrepancies were noted in the Unit 2 containment closeout inspection at the end of the refueling outage. (Section M1.1)

- A procedure execution error by an electrician during the first-time performance of a surveillance procedure caused an engineering safeguards feature actuation and the momentary loss of Unit 2 shutdown cooling. The control room staff responded effectively and restored shutdown cooling within approximately one minute. No increase in reactor coolant system temperature occurred. (Section M1.2)

- The infrequently performed and complex integrated safety injection surveillance test was properly executed by the licensee and demonstrated the ability of Unit 2 safeguards equipment to perform its design basis accident mitigation functions. (Section M1.3)

- A plant electrician made an unauthorized, undocumented change to a preoperational test procedure by inserting a device to block actuation of a relay when the procedure could not be performed as written. (Section M1.4)

- A surveillance procedure for testing undervoltage and underfrequency trips of reactor coolant pumps was inadequate because, when the test was accomplished as written, it resulted in the tripping of the running reactor coolant pump and an automatic start of the turbine-driven auxiliary feedwater pump. Operator response to the event was appropriate. (Section M3.1)

- The attached forms in one maintenance procedure were not controlled in accordance with administrative instructions to ensure that only the latest revisions would be used. However, no instance of the wrong revision being used was identified. (Section M3.2)

Engineering

- Good procedures, preparation, and performance contributed to the successful completion of the preoperational test of a first-of-a-kind diverse scram system. (Section E3.1)

Plant Support

- Following a thorough pre-job briefing, the transfer of resin from the spent resin tank to a high integrity container was performed in an effective manner. Good radiation control practices were observed that minimized the radiation dose to personnel involved with the operation. (Section R1.1)

- The licensee evaluated a case where the spacing between the main steamline and a radiation monitor was greater than specified and determined that the increased spacing had a negligible effect on the radiation field at the detector. Therefore, calculations by the steam release activity computer that determined the amount and rate of radioactive releases to the environment during certain accidents would not have been significantly affected. (Section R2.1)

- Performance of the security force in an event involving the discovery of a controlled substance in a delivery truck was effective. (Section S1)

- Overall, performance of the fire brigade in response to an explosion of the 1M station auxiliary transformer and resultant fire was rapid and effective. (Section F1)

Report Details

Summary of Plant Status

Unit 1 operated at full power until a catastrophic failure of the 1M station auxiliary transformer caused a plant trip on January 5, 1999. Unit 1 returned to full power operation on January 12, and remained there for the duration of the inspection period. Unit 2 completed the cycle 19 refueling outage on December 28, 1998, and returned to near full power operation on January 13, 1999.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (Inspection Procedure (IP) 71707)

The inspectors conducted frequent reviews of plant operations. These reviews included observations of control room evolutions, shift turnovers, operability decisions, and logkeeping. Updated Safety Analysis Report (USAR) Section 13, "Plant Operations," was reviewed as part of the inspection.

b. Observations and Findings

- On December 6, 1998, the inspectors observed Unit 2 control room operators drain the reactor coolant system (RCS) from one foot below the reactor vessel flange to the top of the hot leg in accordance with Special Operations Procedure 2D2.1, “RCS Reduced Inventory Operation After Pool Flood,” Revision 8, Step 5.0. The inspectors verified that all prerequisites, personnel requirements, precautions, and limitations were met prior to beginning the drain down. The actual draining evolution was observed from both the control room and locally at several stations in containment. All personnel were found to be attentive and at their assigned location. Communications remained formal, all equipment responded as expected, and frequent checks of diverse level indications were made.

- On December 13, 1998, an operator mistakenly racked out Unit 1 safeguards bus breaker 16-2 instead of the intended breaker, 16-12. The breaker isolation was being performed in accordance with Work Order (WO) 9812067, “Perform PM [preventive maintenance] on Breaker 221A and 222A Relays and 22A Transformer.” Breaker 16-2, “Bus 16 Source from 1RY Auxiliary Transformer,” was the alternate offsite power source to safeguards bus 16. breaker 16-12, “Bus 16 Feed to 22A Transformer,” provided power to the Unit 1, B train, 480-volt loads. When the wrong breaker was racked out, no engineered safety feature actuations occurred since bus 16 retained power from its normal offsite power source, the CT-11 transformer.

A second operator performing the independent verification on the isolation for breaker 16-12 failed to identify that the wrong breaker had been racked out. The mistake was identified by control room personnel who noticed unexpected breaker position indications on the control room electrical panel. Once the error was identified, breaker 16-2 was racked back in and operability of the breaker verified. The operator, who initially racked out the wrong breaker, self-initiated Employee Observation Report 19983527 on the event.

Breaker 16-2 was not powering bus 16 at the time of the error so the safety significance of the event was minor. If breaker 16-2 had been powering the bus, the inspectors considered it unlikely that the same mistake would have been made since a red light on the front of the breaker cubicle would have alerted the operator to a closed, energized breaker and mechanical interlocks would have physically prevented racking the breaker out. The inspectors were concerned, however, that a safety-related component was mistakenly manipulated and the independent verification failed to identify the error.

Operators failed to properly follow the instructions in WO 9812067, a PM for plant equipment that could have an effect on nuclear safety. This was a violation of TS 6.5 which required that written procedures of that type be followed. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

- The inspectors observed the pre-job briefing for the Unit 2 heatup at the end of the refueling outage. The briefing was conducted by the shift supervisor and was thorough. Precautions were emphasized and the existing plant status was clearly described. Operators asked pertinent questions and had ample opportunities to have any concerns resolved prior to the heatup.

- While observing testing of a newly installed diverse scram system (DSS) on Unit 2 (see Section E3.1), the inspectors noted a weakness in control room logkeeping. During the performance of this test, reactor trip breakers were closed and opened, all control rods were withdrawn to the top of the core twice and then tripped in, and each auxiliary feedwater pump was caused to auto-start. There was no mention of any of these significant equipment manipulations in the reactor log, nor was there a log entry stating that the test had been performed.

  This weakness was discussed with the general superintendent of plant operations and, although it did not constitute a violation of NRC requirements, he agreed that the logs did not adequately reflect the status of the plant during the performance of the test. A memo was sent from the general superintendent to operations department personnel concerning the expectations for log taking. The licensee also planned to conduct testing on the subject during the next operator training cycle.

- Following the Unit 1 station auxiliary transformer explosion and plant trip on January 5, 1999 (see Section O1.5), Unit 1 remained in hot shutdown conditions from January 5 through January 9. During the forced outage, the licensee elected to repair some steam plant leaks which required that the main steam isolation valves (MSIVs) be closed. Once the MSIVs were shut on January 6, hot shutdown conditions were maintained and reactor decay heat was dissipated by venting the steam generators to atmosphere through the steam generator power-operated relief valves (PORVs). On January 8 through 9, the steam generator PORVs were used to cooldown the RCS to less than 350 degrees Fahrenheit (°F) in preparation for restoring reactor coolant pump (RCP) power supplies to Unit 1 sources.

A previous inspection report (50-282/98010(DRS); 50-306/98010(DRS)) discussed a dropped rod and reactor trip event where operators experienced difficulty dissipating reactor decay heat using the steam generator PORVs once the MSIVs had been closed. In contrast to that event, the inspectors noted good control of the steam generator PORVs to maintain hot shutdown conditions and later to cooldown the RCS during the most recent event.

c. Conclusions

Operators demonstrated good control of plant equipment while entering reduced reactor coolant system inventory conditions during the Unit 2 refueling outage. Also, operators responded well to the failure of the Unit 1 auxiliary transformer and maintained control of reactor coolant system temperature by dissipating reactor decay heat using the steam generator power-operated relief valves. The licensee identified a situation, however, where a safeguards bus circuit breaker was mistakenly racked out and the independent verification failed to identify the error. The inspectors identified an instance of inadequate control room logkeeping during testing of a newly installed diverse scram system.

O1.2 Safety Injection (SI) System Walkdown

a. Inspection Scope (IP 71707)

The inspectors performed a general walkdown of portions of the SI system. This system was chosen because of its risk significance as illustrated by the probabilistic risk analysis for the facility. The inspection focused on the piping and components associated with the 21 and 22 SI accumulators.

b. Observations and Findings

The general condition of the equipment inspected was good. Components were clearly marked with labels which identified the component by number and name. The system line-up was consistent with the operating mode (refueling). The following minor discrepancies were identified:

- a slight packing leak on CV-31517 (21 accumulator makeup isolation) as evidenced by a small amount of boric acid buildup on the valve stem;
- a slight body-to-bonnet leak on CV-31462 (22 accumulator upstream check valve test isolation) as indicated by small buildup of boric acid on the side of the valve body;

- a sample tubing connection downstream of 2SI-20-2 (22 accumulator local sample) that was loose and leaking approximately 3 drops per minute; and

- a cracked glass on the local control air pressure gauge for CV-31518 (22 accumulator loop B cold leg makeup isolation).

The inspectors discussed each of the discrepancies with the system engineer responsible for the SI system. The system engineer informed the inspectors that WO 9813283 and WO 9813284 were prepared and provided instructions for cleaning the boric acid residue from CV-31517 and CV-31462 and replacing the cracked gauge glass on the CV-31518 air supply line pressure gauge. He also stated that the body-to-bonnet leak on CV-31462 would be further evaluated after the boric acid residue had been removed and that the compression fitting for the tubing downstream of 2SI-20-2 would be tightened.

c. Conclusions

The material condition of the piping and components associated with the 21 and 22 SI accumulators was good. Prompt corrective actions were initiated by the system engineer to correct some minor material discrepancies identified by the inspectors.

O1.3 22 RCP O-Ring Leak During Unit 2 Heatup

a. Inspection Scope (IP 93702)

The inspectors observed the control room response and reviewed the maintenance history associated with an RCS leak originating from a 22 RCP O-ring seal. The following documents were reviewed as part of this inspection:

- Operating Procedure 2C1.2, “Unit 2 Startup Procedure,” Revision 19;

- WO 9815098, “22 RCP #1 Seal Housing Flange O-Ring Replacement”; and

- Nonconformance Report 19983610, “22 RCP #1 Seal Housing Flange O-Ring Leak.”

b. Observations and Findings

On December 22, 1998, the inspectors were observing RCS heatup being conducted in accordance with Operating Procedure 2C1.2, Step 5.4, when an operator performing a Unit 2 containment inspection reported a large water leak in the vicinity of the 22 RCP vault. The RCS had just reached normal operating temperature and system pressure was approximately 1800 pounds per square inch - gauge (psig) and increasing towards 2235 psig. The control room operators took several prompt and effective actions in response to the reported leak, including stopping RCS pressurization, closely monitoring RCP seal indications, contacting health physics and engineering personnel for support, performing rough RCS leakage calculations using the emergency response computer system, and checking RCP seal package interfacing systems for potential sources of leakage. The shift supervisor provided strong leadership and ensured operators remained focused on maintaining stable plant conditions.

Approximately 30 minutes after the leak was reported, the reactor operator requested a status update from the shift supervisor. This was a particularly timely and useful request and demonstrated the operator's desire to understand the larger implications of the leak. The Unit 2 shift supervisor subsequently briefed the shift manager, Unit 1 shift supervisor, shutdown operations coordinator, and the control room crew on the available information. The update was important since not all personnel in the control room were aware of the most recent information and the intended course of action. Following the update, the decision was made to reduce RCS pressure to about 1600 psig, as allowed by Operating Procedure 2C1.2 for the current temperature.

Investigation revealed that the leak was from the O-ring seal located between the RCP impeller casing and the seal package and was unisolable. Based on the location and source of the leak, the decision was made to return to cold shutdown conditions to effect seal repairs. Seal repairs were subsequently completed in accordance with WO 9815098 and plant heatup resumed on December 27, 1998. The leak resulted in approximately 200 gallons of water draining to the floor drains. See Section M1.1 of this report for a discussion of the cause of the leak.

c. Conclusions

Control room operators took prompt and effective actions to locate, minimize, and quantify an RCS leak during plant heatup on Unit 2. A reactor operator requested a leak status update that was particularly useful in ensuring all operators and shift management had the most recent information and understood the intended course of action.

O1.4 Unit 2 Reactor Startup and Return to Full Power Operation

a. Inspection Scope (IP 71707)

Between December 31, 1998, and January 8, 1999, Unit 2 was restarted from the refueling outage and returned to near full power operation. The inspectors observed portions of the RCS heatup, equipment realignment for power operation, control rod withdrawal to criticality, physics testing, and power ascension. The following documents were reviewed as part of this inspection:

- Operating Procedure 2C1.2, "Unit 2 Startup Procedure," Revision 19;
- Operating Procedure 2C1.4, "Unit 2 Power Operation," Revision 17;
- Operating Procedure C1B, "Appendix - Reactor Startup," Revision 6;
- Maintenance Procedure D30, "Post Refueling Startup Testing," Revision 29;

- Maintenance Procedure D32, “Temperature Coefficient Measurement at Hot Zero Power,” Revision 7;
- Maintenance Procedure D34, “Boron Endpoint Measurement,” Revision 6;
- Surveillance Procedure (SP) 2036, “Turbine Overspeed Trip Test and Setpoint Verification,” Revision 20;
- Temporary Change Notice (TCN) 19990015, “SP 2036/WO 9809602,” dated January 2, 1999; and
- TCN 19990016, “TCN,” dated January 3, 1999.

b. Observations and Findings

For the reactor startup and approach to criticality, the pre-job briefing was adequate and included a complete review of all precautions. Duties of each individual member of the operations team were clearly designated. Two extra reactor operators and one extra shift supervisor were assigned. This allowed the operators actually performing and supervising the approach to criticality to focus solely on that evolution. Reactor startup and approach to criticality were conducted in a slow, deliberate, and controlled manner. No significant discrepancies were noted. Since this was the first reactor startup following a refueling outage, criticality was achieved by diluting the RCS. Criticality occurred near the predicted point and was properly identified and recorded. Control room communications were formal.

The inspectors observed portions of the low power physics testing program as described in Maintenance Procedures D30, D32, and D34. Good coordination was observed between the nuclear engineer coordinating the testing and the duty reactor operator who performed many control rod manipulations and RCS heatup and cooldown transients to support the testing.

The inspectors observed initial attempts to parallel the main generator with the power grid on January 1, 1999. When the lead reactor operator (LRO) attempted to adjust generator frequency in accordance with Operating Procedure 2C1.2, Step 5.6.13.B, turbine speed unexpectedly increased approximately 50 revolutions per minute (rpm) until the overspeed protection circuit closed the turbine intercept valves to limit the speed increase. The LRO took manual control and unsuccessfully attempted to reduce speed before the overspeed protective circuit again limited the turbine speed increase. Because of the lack of speed control, the shift supervisor ordered the turbine tripped from the control room. Subsequent investigation determined that steam leakage through one of the turbine control valves, CV-3, was the cause for the turbine speed increase even though the electrohydraulic system had been attempting to close the control valves. Programmed CV-3 response was then lagged approximately five percent behind another control valve, CV-4, and the generator was paralleled to the grid on January 3, 1999.

During the second attempt to parallel the main generator to the grid on January 3, the inspectors observed good crew communications and attentiveness to plant parameters. Roll-up of turbine speed from 0 to 1800 rpm, turbine bearing vibration and lubricating oil temperatures, raising field voltage, closing the main generator breaker, transition of reactor power from the steam dumps to the initial 25 megawatts of electrical load, and CV-3 and CV-4 programmed responses were monitored and controlled well.

Portions of four different procedures applied to plant operations during paralleling operations on January 3, Maintenance Procedure D30, Operating Procedures 2C1.2 and 2C1.4, and TCN 19990015. Just prior to closing the main generator breaker, the LRO demonstrated excellent procedural awareness by noting that the valve position limiter needed to be raised to indicate 105 percent in accordance with 2C1.2, Step 5.6.10.Y.8. The primary procedure being used to parallel the generator to the gird on January 3 was TCN 19990015, but it did not include discussion of the valve position limiter setting. Subsequently, TCN 19990015 was modified by TCN 19990016 to include the correct valve position limiter setting prior to synchronizing the main generator with the grid.

Following synchronization to the grid, power ascension continued without problems. New turbine components contributed to elevated sodium levels in the condensate, feedwater, and steam generator systems. As a result, several chemistry holds slowed power ascension while condensate filtering and polishing systems removed the excess sodium.

c. Conclusions

Unit 2 reactor startup, approach to criticality, and low power physics testing were performed in a slow, controlled, and deliberate manner. Operators responded appropriately to unexpected turbine speed control responses during initial attempts to parallel the main generator to the grid. The second, successful attempt to parallel to the grid was characterized by good crew communications, attentiveness to plant parameters, and procedural awareness. Subsequent power ascension and return to near full power operations occurred with no discrepancies.

O1.5 1M Station Auxiliary Transformer Explosion and Unit 1 Reactor Trip

a. Inspection Scope (IP 93702)

On January 5, 1999, Unit 1 automatically tripped from 100 percent power because of an explosion of the 1M station auxiliary transformer. The inspectors observed and reviewed the initial licensee response to the transformer explosion and Unit 1 reactor trip, and the subsequent actions to place the reactor plant in a safe and stable condition. The inspectors also evaluated the licensee's efforts to determine the cause and scope of the damage and return the unit to operation.

b. Observations and Findings

The inspectors observed the actual explosion of the transformer from a window of the resident inspector's office, which overlooks the Unit 1 transformers. The blast separated the top part of the transformer shell and sprayed flaming oil approximately 100 feet laterally out of the open end of the 1M transformer enclosure. The explosion was apparently caused by an internal transformer short which also caused a main generator trip and subsequent reactor trip. A portion of the fire was around the base of the closest power line tower to the adjacent 1R reserve auxiliary transformer. Charring could be seen on the south face of the tower and on the south facing power line insulators.

The heavy smoke from the oil fire apparently shorted the B and C phases of lines to the 1R transformer, which in turn caused a lockout of two of the switchyard breakers feeding the 1R transformer. This caused a loss of the RCPs, feedwater pumps, and other nonsafeguards equipment powered from buses 11, 12, 13, and 14. Safeguards bus 15, normally powered from the 1R transformer, automatically sequenced onto transformer CT-11. Safeguards bus 16, normally powered from the CT-11 transformer, was not affected. Neither of the Unit 1 emergency diesel generators started during this event because power was not lost to the safeguards buses. No personnel were injured during the explosion and subsequent fire. See Section F1 for a discussion of the fire brigade response to this event.

The inspectors responded to the control room minutes after the explosion. A brief time line of the event and reactor trip recovery was as follows:

- 1:11 p.m. 1M station auxiliary transformer exploded. Unit 1 turbine and subsequent reactor trip.

- 1:14 p.m. All the control rods were verified to be on the bottom, both auxiliary feedwater pumps had auto-started and were supplying the 11 and 12 steam generators, and the control room crew was carrying out the actions of ES-0.1, "Reactor Trip Recovery."

- 1:40 p.m. Natural circulation was verified, steam generator levels were coming back on scale, and the licensee made a Notification of Unusual Event to the NRC. The Notice of Unusual Event was made due to a "visually observed evidence of an unplanned or unexplained explosion within the owner controlled fence but not affecting plant safe operation."

- 1:50 p.m. Steam generator levels were back on scale.

- 2:35 p.m. Power was restored to nonsafeguards buses 13 and 14 from Unit 2 transformer 2RY.

- 3:00 p.m. The licensee implemented the cooldown action time limits of Technical Specification (TS) 3.0.C because TS 3.1.A.1.b required that both RCPs be operable with RCS temperature greater than 350°F. With no power to buses 11 and 12, both RCPs were inoperable.

- 5:50 p.m. Completed borating to hot shutdown concentration.

- 6:20 p.m. Power was restored to buses 11 and 12 from Unit 2 transformer 2RX. This was significant because the RCPs were powered from these buses.

- 6:40 p.m. Started 12 RCP. Forced circulation in RCS was restored. The action requirements of TS 3.0.C were halted. No actual cooldown had been initiated.

- 6:51 p.m. Exited the Notice of Unusual Event.

- 7:10 p.m. Started 11 RCP.

The inspectors observed the competent execution of the emergency procedures by the duty control room operators. The reactor operator maintained positive control of RCS inventory, pressure, and temperature throughout the event. Off-shift licensed operators effectively supplemented the duty crew, allowing the duty crew to remained focused on placing/maintaining the reactor plant in a safe condition. The inspectors noted good coordination among the electrical engineers, on-shift operators, and off-shift operators during the electrical isolation of the 1M transformer and the restoration of power to the Unit 1 nonsafeguards electrical buses.

Over the next few days, restoration actions included testing and restoration of the 1R transformer and the Unit 1 generator transformer. Except for the 1M transformer, which was unusable, the only significant damage found was some charred insulators on the power line tower to the 1R transformer and some metal spattering on the power lines leading to that tower. The insulators were replaced and the deposits were cleaned off the power lines. All testing was completed satisfactorily with no discrepancies found. The licensee did not expect to be able to replace the 1M transformer until the next Unit 1 refueling outage. The licensee intended to issue a Licensee Event Report (LER) to describe the event and corrective actions. The LER will be considered open when issued.

c. <u>Conclusion</u>

Licensee personnel responded well to the explosion of the 1M station auxiliary transformer and subsequent fire. Control room personnel quickly determined the cause of the reactor trip and took actions to place the reactor plant in a safe and stable condition. Restoration actions were comprehensive and adequately addressed short-term and long-term equipment issues.

O1.6 <u>Unit 1 Startup Following Failure of the 1M Station Auxiliary Transformer</u>

a. <u>Inspection Scope (IP 71707)</u>

Between January 11-12, 1999, Unit 1 was restarted and returned to full power operation. The inspectors observed portions of the RCS heatup, control rod withdrawal to criticality, and the subsequent power ascension. The following documents were reviewed as part of this inspection:

- Operating Procedure 1C1.2, “Unit 1 Startup Procedure,” Revision 20;
- Operating Procedure 1C1.4, “Unit 1 Power Operation,” Revision 16; and
- Operating Procedure C1B, “Appendix - Reactor Startup,” Revision 6.

b. Observations and Findings

The reactor startup and approach to criticality were conducted in an attentive, deliberate manner. Control room distractions were minimized. Extra operations personnel were assigned to the crew allowing the operators and supervisor to focus solely on the reactor startup. Control room communications were formal. Coordination between the nuclear engineer and reactor operator was good, with both conducting independent reactivity predictions and comparing the results frequently. Criticality occurred at a somewhat higher control rod height than predicted but was within the allowed band. Reactor criticality was properly identified. Power ascension occurred normally with no discrepancies noted.

c. Conclusion

The Unit 1 reactor startup, approach to criticality, and power ascension following the Unit 1 station auxiliary transformer explosion were performed in an attentive, well controlled manner.

O1.7 Review of Plant Cold Weather Preparations

a. Inspection Scope (IP 71714)

The inspectors reviewed the site preparedness for winter plant operation.

b. Observations and Findings

The inspectors verified that Special Test Procedure 1637, “Winter Plant Operations,” Revision 23, had been completed and that the areas of the plant covered by this procedure were adequately protected from the weather. Specifically, some of the buildings covered by this procedure were the gas house, auxiliary building, screenhouse, cooling tower equipment and pump houses, turbine room, guardhouse emergency diesel room, intake screenhouse, deepwell pumphouses, and D5/D6 safeguards diesel building. On the day the inspectors performed this inspection, actual outside temperature was minus 10°F. All areas inspected were warm, dry, and adequately protected from the outside weather.

c. Conclusions

The licensee’s cold weather preparations were adequate to protect the selected areas of the plant from severe winter weather.

O3 Operations Procedures and Documentation

O3.1 Inconsistent Definition of Hot Shutdown Mode

t. Inspection Scope (IP 92901)

The inspectors reviewed the licensee's use and definition of the term "hot shutdown" and verified that TS requirements for mode changes to that condition were met.

u. Observations and Findings

During observations of plant startup evolutions, the inspectors noted that various licensee documents contained inconsistent uses of the term "hot shutdown." Definitions Table 1-1 of the TS-defined HOT SHUTDOWN mode as subcritical with RCS temperature greater than or equal to 350°F. This was also called MODE 3. However, the operators normally referred to the plant as being in hot shutdown only when the RCS was above 535°F, the minimum temperature for reactor startup. An example was in Operating Procedure 1C1.2, "Unit 1 Startup Procedure," Revision 20, Step AB, which stated "WHEN RCS temperature is greater than 535°F AND RCS pressure is 2235 psig (RCS Heatup complete), then **perform** the following: **Log** RCS at Hot Shutdown in the Reactor Log." The inspectors informed the general superintendent of plant operations of the inconsistency.

The inspectors reviewed TS operability requirements and Operating Procedure 1C1.2 and noted that the procedure contained steps to verify that all Mode 3 TS requirements were met before exceeding 350°F during a heatup. Thus, the misuse of the term "hot shutdown" had no safety significance.

v. Conclusions

The inspectors identified that operators and licensee procedures did not use the same definition of the term "hot shutdown" as that in the TS.

O8 Miscellaneous Operations Issues (IPs 92700 and 92901)

O8.1 (Closed) Violation (VIO) 50-282/97023-03(DRP): Failure to Perform Two Steps in Reactor Physics Testing Procedure as Written. This issue was previously discussed in Inspection Report 50-282/97023(DRP); 50-306/97023(DRP), Section M1.2. The licensee responded to the violation and discussed the corrective actions in a letter to the NRC dated February 26, 1998. As stated in the response, the corrective action was to revise Maintenance Procedure D32, "Temperature Coefficient Measurement at Hot Zero Power," to reflect the required test criteria. The inspectors reviewed the revision to D32 and observed the successful use of the revised procedure during low power physics testing for Unit 2 (see Section O1.4). The inspectors also acknowledged an on-going plant-wide initiative by the licensee to train all site personnel on the importance of procedure adherence and the timely correction of identified procedure errors. The inspectors determined that the corrective actions for this violation were acceptable.

O8.2 (Closed) LER 50-306/97003 (2-97-03): Auto-Start of 22 Turbine-Driven Auxiliary Feedwater Pump on Undervoltage Signal and Entry Into TS 3.O.C for the Inoperability of Reactor Coolant Pumps When Buses 21 and 22 Were De-energized. This event was previously discussed in Inspection Report 50-263/97011(DRP); 50-306/97011(DRP), Section O8.1.

The inspectors contacted the superintendent of electrical systems engineering and reviewed the two corrective actions associated with the LER. The first action evaluated removing the undervoltage start function when the pump was placed in shutdown auto. The superintendent stated that the undervoltage start function would not be removed from the pump and no circuit modifications would be made since the original auto-start was the result of human error vice a design problem or deficiency. The second action evaluated revising plant Operating Procedures 1C20.5 and 2C20.5, Sections 5.9 and 5.10, concerning the transfer of power sources for buses 21 and 22. The superintendent stated that the procedures were in the licensee's revision program and were to be reviewed and approved by the Operations Committee (the onsite review committee) in several weeks.

O8.3 (Closed) LER 50-306/98005 (2-98-05): Turbine Trip/Reactor Trip from 22 Percent Power during Planned Shutdown Operation. This event was previously discussed in Inspection Report 50-263/98020(DRP); 50-306/98020(DRP), Section O1.4. At the time of that report, the LER had not been issued. The inspectors reviewed the LER when issued and had no concerns. Although the exact cause of the reactor trip was not determined, the corrective actions taken were reasonable.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (IPs 61726, 62707, and 92902)

The inspectors observed all or portions of the maintenance and surveillance activities listed below. Included in the inspection was a review of the SPs and WOs listed, as well as the appropriate USAR sections regarding the activities. The inspectors verified that the SPs for the activities observed met the requirements of the TSs. The following activities and procedures were reviewed by the inspectors:

- SP 1054, "Turbine Stop, Governor, and Intercept Valve Test," Revision 18;
- SP 2036, "Turbine Overspeed Trip Test and Setpoint Verification," Revision 20;
- SP 2047, "Control Rod Exercise," Revision 30;
- SP 2083, "Unit 2 Integrated SI Test With A Simulated Loss of Offsite Power," Revision 22;

- SP 2750, “Post Outage Containment Close-Out Inspection,” Revision 16;
- WO 9815020, “SI Pump Miniflow Annunciator Would Not Clear”; and
- WO 9900177, “Verify Condition of 1G Isophase Ground Straps.”

b. Observations and Findings

- The inspectors accompanied licensee personnel performing a Unit 2 containment close-out inspection in accordance with Part B of SP 2750. At the time of the close-out inspection, the RCS was at approximately 350°F and progressing towards the normal operating temperature, 547°F. All tape, cloth, bags, rope, non-permanent radiation postings, hoses, ducts, and fire extinguishers were removed from containment. The containment recirculation sump was clear of debris and the screens were free of damage. No discrepancies were noted.

- As discussed in Section O1.3 of this report, the licensee identified an RCS leak from the 22 RCP seal. The licensee determined that an incorrect O-ring had been installed on the 22 RCP #1 seal housing flange, causing a leak past the O-ring when system pressure exceeded 1500 psig. The 22 RCP was unique in that it contained a different O-ring groove which required the ordering of a non-standard, high temperature replacement kit. The standard O-ring replacement kit was mistakenly ordered and initially installed in 22 RCP during cycle 19 refueling outage maintenance activities. A corrective action item was written to update the 22 RCP parts list to prevent recurrence.

c. Conclusions

Most maintenance and surveillance activities observed were performed properly. No discrepancies were noted in the Unit 2 containment closeout inspection at the end of the refueling outage. Other conclusions regarding specific maintenance and surveillance activities are contained in other sections of this report.

M1.2 Momentary Loss of Shutdown Cooling During Turbine Building Cooling Water Header Isolation Valve Tests

a. Inspection Scope (IPs 62707 and 71707)

The inspectors reviewed the circumstances and operator actions associated with a momentary loss of Unit 2 shutdown cooling that occurred on December 19, 1998.

b. Observations and Findings

In accordance with SP 2126, “Unit 2 Turbine Building Cooling Water Header Isolation Valves SI Relays 2SI-12X and 2SI-22X,” Revision 0, the licensee was testing auxiliary SI contacts and circuitry associated with two relays that had not been tested during the performance of SP 2083, the integrated SI test. The procedure had been issued on December 15, and was being used for the first time on December 19, 1998. In accordance with Step 6.1, the electrician established contact with the control room.

Later, in accordance with Steps 7.1.15 and 7.1.16, the electrician was to manually engage relay 2SI-12X and record the time until the blue light on CS-46038, “1 Turbine Building Cooling Water Header Supply Valve, MV-32031,” was lit. While contacting the control room and counting down the time towards initiation of Step 7.1.15, the electrician inadvertently shifted his hand and mistakenly initiated relay 2SI-11X instead of relay 2SI-12X.

When relay 2SI-11X was engaged, a safeguards bus 25 load rejection signal occurred causing the loss of the running 21 component cooling water and 21 residual heat removal pumps. The standby 22 component cooling water pump automatically started on a low cooling water header pressure signal. The control room operators responded effectively and rapidly started standby 22 residual heat removal pump to restore shutdown cooling. Shutdown cooling was lost for approximately one minute, with no measurable increase in RCS temperature, thus the event was of only minor safety significance.

The licensee reported the momentary loss of shutdown cooling to the NRC in accordance with 10 CFR 50.72 and an Error Reduction Task Force investigation into the event was initiated. Subsequently, SP 2126 was completed using two electricians to perform Steps 7.1.15 and 7.1.16. The licensee intended to issue LER 2-98-06 describing the event and corrective actions. The LER will be considered opened when issued.

Technical Specification 6.5 required, in part, that procedures be prepared and followed for surveillance and testing requirements that could have an effect on nuclear safety. On December 19, 1998, a licensee electrician inadvertently failed to follow SP 2126 when he actuated the wrong relay. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

A procedure execution error by an electrician during the first-time performance of a surveillance procedure caused an engineering safeguards feature actuation and the momentary loss of Unit 2 shutdown cooling. The control room staff responded effectively and restored shutdown cooling within approximately one minute. No increase in reactor coolant system temperature occurred.

M1.3 Unit 2 Integrated SI Test With A Simulated Loss Of Offsite Power

a. Inspection Scope (IP 62707)

On December 18, 1998, the inspectors attended the pre-job briefing for and observed the performance of the Unit 2 SI test being conducted in accordance with SP 2083, “Unit 2 Integrated SI Test With A Simulated Loss of Offsite Power,” Revision 22. This was an infrequently performed, complex test that demonstrated actuation of both trains of emergency core cooling equipment and both emergency diesel generators.

b. Observations and Findings

The pre-job briefing was comprehensive and included discussion of prerequisites, initial conditions, contingency actions, roles and responsibilities, communications, equipment status, abnormal configurations, expected transients, timing sequences, and data collection assignments. All personnel directly involved in the test were present at the briefing as well as the plant manager and general superintendents of plant operations, engineering, and instrumentation and control engineering. The plant manager discussed expectations for the test including personnel safety, nuclear safety, equipment protection, and formal communications.

The inspectors observed the test from the control room and locally from the safety injection pump and emergency diesel generator areas. Pre-initiation checklists in each of these areas were properly completed. The inspectors noted that the licensee paid particular attention to ensure that no unplanned or conflicting TS Limiting Condition for Operation action requirements were entered because of the complexity of the test and the status of plant systems in a refueling outage.

Upon initiation of the safety injection signal, the emergency diesel generators achieved rated speed and voltage within 10 seconds, and the load sequencer correctly stripped and then restored safeguard bus loads. Locally at the safety injection pumps, the inspector and local operators noticed that both pumps started, ran for approximately ten seconds, and then were secured. Since this was not the expected equipment response, the local operator contacted the control room. Control room personnel reported that the pumps had been manually secured after receiving a recirculation low flow alarm for both safety injection pumps. When contacted, the system engineer informed the inspectors that WOs 9815020 and 9815033 were issued to investigate the cause of the low flow alarm. A sticking relay associated with the 21 SI pump minimum recirculation line flowmeter was identified in WO 9815020. Work Order 9815033, although not complete at the end of this inspection period, required retesting of the sticking relay and replacement of a flowmeter circuit board, if necessary.

The inspectors also noted that as soon as the D6 safeguards diesel generator started, the lube oil filter high differential pressure alarm for each engine illuminated at the local D6 alarm annunciator panel and remained lit for the entire time that the engines were operating. The inspectors asked the system engineers responsible for the D5 and D6 safeguards diesels, who were present for the performance of the SP, about the validity of the alarms. The engineers informed the inspectors that even though the alarms were valid, based on numerous other lube oil temperature and pressure indications for each engine, the duplex lube oil filters were not plugged. They also stated that after the test was completed, that the duplex filter would be shifted and the dirty filter replaced.

The inspectors noted that the LRO conducting the test from the control room performed well. He directed the activities of several reactor operators and received and recorded the reports from the members of the field teams. Throughout the test, the LRO maintained awareness of the changing plant status, prevented distractions, and responded properly to unexpected conditions.

c. Conclusions

The infrequently performed and complex integrated safety injection surveillance test was properly executed by the licensee and demonstrated the ability of Unit 2 safeguards equipment to perform its design basis accident mitigation functions.

M1.4 Failure to Use the Approved Procedure Change Process

a. Inspection Scope (IP 92902)

The inspectors reviewed the circumstances of the event, identified by the licensee, in which foreign material prevented the proper operation of a relay. The inspectors reviewed the following documents:

- Nonconformance Report 19983572, "Pen Found in 27S/B21 Relay";
- WO 9811257, "Perform Pre-op Test on AMSAC/DSS [Anticipated Transient Without Scram Mitigation System Actuation Circuit/Diverse Scram System] - Block Mode"; and
- WO 9815091, "Verification of 21 & 22 RCP Inputs to AMSAC & ERCS [Emergency Response Computer System]."

b. Observations and Findings

On December 16, 1998, during the performance of testing in accordance with SP 2015, "4KV [kilovolt] Bus 21/22 Undervoltage and Underfrequency Relay Test," Revision 17, a licensee electrician noted that for Step 7.11.3, one of three expected alarms did not occur. The system engineer was contacted and in the subsequent investigation, licensee personnel found a black permanent marker pen lodged in the wire loop at the base of the 27S/B21 relay. This prevented the relay from actuating on an undervoltage condition, thus preventing the alarm from occurring. The marker was removed and SP 2015 was completed with no other abnormalities.

The licensee's investigation revealed that during AMSAC/DSS preoperational testing on December 10, a plant electrician had placed the marker in the 27S/B21 relay to assist in the execution of WO 9811257, "Perform Preoperational Test on AMSAC/DSS - Block Mode," Steps 7.24 and 7.25. The marker was used as a mechanical block when the electrician found that he could not successfully complete the procedure as written. This was not documented with a Temporary Change Notice in the WO or by any other means. At the end of the test, the electrician forgot to remove the marker.

Licensee corrective actions included removing the marker, examining all 4-KV safeguards and non-safeguards cubicles and relay cabinets to ensure no similar mechanical blocks were in place, and issuing WO 9810591 to repeat preoperational testing steps 7.24 and 7.25. The electrician was counseled regarding the need for proper authorization and documentation of procedure changes.

Relay 27S/B21 was designed to provided an undervoltage and underfrequency trip of the 21 RCP. That function would have been disabled if the blocked relay had not been discovered. However, the problem was discovered and corrected in the cold shutdown mode when the RCPs were not operating and the trip was not required to be operable. Thus, for this particular event, the safety significance of blocking the relay was minor. However, the failure on the part of the electrician to follow established procedure change processes when it became necessary to deviate from a surveillance procedure was of greater concern and was of more than minor safety significance because it involved plant protective circuits and an uncontrolled modification to a system.

Technical Specification 6.5.G required, in part, that temporary changes to Operations Committee reviewed procedures may be made with the concurrence of two members of the unit management staff, at least one of whom holds a senior reactor operator license, and that such changes be documented and reviewed by the Operations Committee. On December 10, 1998, by using the marker to block the relay, the electrician added a step to WO 9811257, an Operational Committee reviewed procedure for testing of plant protective circuits, without approval or documentation. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-306/98023-01(DRP)).

c. <u>Conclusions</u>

The licensee identified that a plant electrician had made an unauthorized, undocumented change to a preoperational test procedure by inserting a device to block actuation of a relay when the procedure could not be performed as written.

M3 Maintenance Procedures and Documentation

M3.1 <u>Inadvertent Trip of RCP During Surveillance Test</u>

a. <u>Inspection Scope (IP 92902)</u>

On January 8, 1999, while Unit 1 was in hot shutdown, the only operating RCP tripped during a surveillance test. This resulted in the loss of all forced RCS circulation cooling and reliance on natural circulation cooling for about 44 minutes. The inspectors reviewed the licensee’s recovery actions and investigation into the cause of the problem. The following documents were reviewed:

- SP 1016, “RCP Breakers Test,” Revision 12;
- SP 1016, “RCP Breakers Test,” Revision 10; and
- SP 2016, “RCP Breakers Test,” Revision 16.

b. <u>Observations and Findings</u>

The licensee was testing RCP undervoltage and underfrequency trips in accordance with SP 1016, “RCP Breakers Test,” Revision 12. The 11 RCP was secured with its breaker in the test position. The underfrequency portion of the test was conducted by simulating an underfrequency condition to both the 11 and 12 RCPs. This would normally cause both RCPs to trip. Previous revisions of SP 1016, through Revision 10, contained steps to disconnect the appropriate leads prior to injecting the underfrequency signals so that the running RCP did not actually trip. However, Revisions 11 and 12 of SP 1016, issued in 1997, did not contain those steps. The similar procedure for Unit 2, SP 2016, “RCP Breaker Test,” Revision 16, did contain the steps to lift the leads. Thus, when the underfrequency condition was simulated in Step 7.1.33 of SP 1016, both RCP breakers tripped.

During the performance of the test, an automatic start of the turbine-driven auxiliary feedwater pump also occurred, as designed, because of undervoltage signals on both the 11 and 12 buses. The licensee’s investigation determined that the start was due to another error in the procedure. Step 7.1.30 contained instructions to simultaneously open knife switches powering the undervoltage relays for both buses 11 and 12.

Operators responded to the loss of forced circulation properly. They verified that natural circulation cooling of the RCS had initiated, reset the trips on the RCPs, and restarted the 12 RCP. The reactor was without forced circulation for about 44 minutes. Natural circulation cooling was adequate and RCS temperatures remained normal.

The licensee reported the event to the NRC in accordance with 10 CFR 50.72 and intended to submit a followup LER. The LER will be considered open when issued. Loss of forced circulation flow was considered a condition prohibited by TS and required entry into the “motherhood” action requirements of TS 3.0.C. However, flow was restored before a cooldown to below 350°F would have been required.

The system engineer initiated Nonconformance Report 19990096 to document the investigation of the cause and corrective actions for the event. The licensee’s Error Reduction Task Force also initiated an investigation. The preliminary results at the end of this inspection period indicated that Revision 11 to SP 1016, which was intended only to convert the document to a different computer software database, did not convert the critical steps to lift the leads. The investigation into the cause and potential wider effects of that problem was continuing. The inadequate step which resulted in the start of the auxiliary feedwater pump had apparently always been a part of the procedure. The procedure errors had not been revealed earlier because the test was normally accomplished while in cold shutdown conditions with both RCP breakers in the test position and the turbine-driven auxiliary feedwater pump in manual.

Criterion V, “Instructions, Procedures, and Drawings,” of Appendix B, of 10 CFR Part 50, required, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Procedure SP 1016, Revision 12, a procedure for an activity which tested reactor protection system features and could affect reactor coolant system forced circulation cooling, was not appropriate to the circumstances because it did not contain steps to prevent tripping of the running RCP and automatic starting of the turbine-driven auxiliary feedwater pump. In this case, the issue was not of high safety significance because the reactor was designed such that adequate natural circulation cooling was automatically established upon loss of forced circulation. The cause of the event was identified by the licensee and had been entered into their corrective action system. Adequate progress was being made on identifying and correcting the root cause of the event. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-282/98023-02(DRP)).

c. Conclusions

A surveillance procedure for testing undervoltage and underfrequency trips of RCPs was inadequate because, when the test was accomplished as written, it resulted in the tripping of the running RCP and an automatic start of the turbine-driven auxiliary feedwater pump. Operator response to the event was appropriate.

M3.2 Review of Prairie Island Nuclear Generating Plant (PINGP) Forms

a. Inspection Scope (IP 92902)

The inspectors reviewed the use of PINGP forms to verify conformance with the guidance provided in Administrative Work Instructions 5AWI 1.5.0, “Procedure Control,” Revision 4, and 5AWI 4.2.0, “QA [Quality Assurance] Forms Control,” Revision 2.

b. Observations and Findings

At Prairie Island, PINGP forms were used as checklists, logs, charts, schematics, and other special applications. Each of the administrative work instructions provided the instruction that PINGP forms should not be used in standing or preventive maintenance procedures, but if used, “they shall be identified as typical and the procedure shall require that the current revision of the form be used.” In general, the inspectors noted that if a PINGP form was used in a standing or preventive maintenance procedure that instructions were provided by that procedure to obtain the most current copy of the form. Also, if the PINGP form was provided as an attachment to a procedure, that these forms were labeled as “example only - use current revision.”

However, the inspectors found two examples of PINGP forms that did not meet the guidelines of 5AWI 1.5.0 or 5AWI 4.2.0. They were PINGP Form 1197, “Scaffold Construction Combustible Loading and Evaluation Log” and PINGP Form 1198, “D80 Scaffold Construction Checklist.” The forms were Attachments A and B to Maintenance Procedure D80, “Scaffolding and Ladder Construction Use,” Revision 10. The maintenance procedure did not provide instructions to use the current revision of the PINGP form or mark the attachments as “example only.”

The inspectors performed a spot check of recently constructed scaffolding to verify that the most current revision of PINGP Forms 1197 and 1198 were actually being used in the plant. The inspectors found no discrepancies. Thus, the issue did not constitute a violation of NRC requirements. The plant staff person responsible for the procedure was notified and he informed the inspectors that the corrections would be made to the procedures.

c. Conclusions

The inspectors identified a procedure in which attached forms were not controlled in accordance with administrative instructions to ensure that only the latest revisions would be used. However, no instance of the wrong revision being used was identified.

M8 Miscellaneous Maintenance Issues (IPs 92700 and 92902)

M8.1 (Closed) LER 50-282/98009; 50-306/98009 (1-98-09): Reactor Coolant Vent System Testing. This issue was previously discussed in Inspection Report 50-282/98015(DRP); 50-306/98015(DRP), Section M3.1. As stated in the LER, the corrective actions taken to address this issue included the submittal of a license amendment request which would clarify the wording in the TS regarding the testing of the reactor coolant gas vent system and the modification of applicable surveillance procedures to ensure that all of the reactor coolant vent system piping, required to be flow tested, was done at the required interval. The inspectors reviewed the license amendment request, SP 1248, "RCGVS [reactor coolant gas vent system] Testing Unit 1," Revision 10, and SP 2248, "RCGVS Testing Unit 2," Revision 8, and found them to be acceptable. The TS amendment was approved by the NRC on December 17, 1998.

III. Engineering

E3 Engineering Procedures and Documentation

E3.1 AMSAC/DSS Testing

a. Inspection Scope (IP 37551)

The inspectors reviewed Preoperational Test Procedure 9811261, "AMSAC/DSS Preoperational - Rod Drop Test," Revision 0, and observed the performance of the test.

b. Observations and Findings

The AMSAC/DSS system was a first-of-a-kind system installed to actuate a reactor trip using a diverse method (de-energizing the control rod stationary gripper coils) upon indications of failure of the reactor to trip when required. The purpose of the test was to verify proper actuation of a diverse reactor trip, turbine trip, and auxiliary feedwater start with the newly installed AMSAC/DSS circuits, and to verify that the time between the actuation signal and when all control rods were on the bottom met acceptance criteria.

The inspectors attended the pre-job briefing for the test. The briefing was thorough and incorporated specific duties of personnel participating in the test and contingency actions for potential abnormal plant conditions. The performance of the test was completed satisfactorily with the desired performance data obtained. The system worked as designed on the first attempt. Good coordination was observed among engineering, operations, and instrument and control personnel. The performance of the test required many electrical jumpers and bypasses be installed and removed to set up the proper testing conditions. The inspectors observed many of the jumper installations and noted no discrepancies.

c. Conclusions

Good procedures, preparation, and performance contributed to the successful completion of the preoperational test of a first-of-a-kind diverse scram system.

E3.3 USAR Discrepancies Concerning RCP Bus Underfrequency Trips

While investigating the unexpected trip of an RCP during testing (see Section M3.1), the inspectors noted two editorial errors in the USAR. Section 7.4.1.2.3.14.b and Table 7.4-1, Item 8.b_3, each referred to another section of the USAR. In both cases, the referenced section was incorrect. Upon review, the inspectors noted that both errors had previously been identified by the licensee's USAR review group and corrections had been drafted.

E8 Miscellaneous Engineering Issues (IPs 92700 and 92903)

E8.1 (Closed) LER 50-282/97012; 50-306/97012 (1-97-12): Chemical and Volume Control System Malfunction Unanalyzed for Boron Dilution During Shutdown Modes of Operation. This LER was previously discussed in Inspection Report 50-282/97021(DRP); 50-306/97021(DRP), Section E8.6. The LER reported that plant operation during cold or hot shutdown modes with the shutdown margin required by the TSs would not provide the time identified in the USAR for operator action to mitigate an inadvertent boron dilution. Licensee corrective actions for this violation were followed by Commitment Tracking Numbers 19980014 and 19980015.

The inspectors verified that for Commitment 19980014, evaluation of procedures to ensure adequate mixing when residual heat removal operation was aligned to the vessel injection path had been completed. Commitment 19980015 required the boron dilution analysis described in Section 14.4.4 of the USAR to be performed for all operating modes. The inspectors reviewed this commitment and learned that the licensee nuclear analysis personnel had completed the required analysis for the cold and hot shutdown modes. As part of the analysis, the nuclear analysis personnel proposed that a license amendment request to change the TS to include hot and cold shutdown boron concentration requirements be submitted by the end of January 1999.

E8.2 (Closed) LER 50-282/98001; 50-306/98001 (1-98-01), Original: Leakage through Redundant Control Room Steam Exclusion Dampers Found to Exceed Value Assumed in the HELB [High-Energy Line Break] Analysis. On February 12, 1998, the licensee submitted Supplement 1 to the LER, which slightly modified some of the long-term corrective actions. Thus, the original LER is closed to prevent duplicate tracking. Supplement 1 of the LER remains open pending completion of the corrective actions.

E8.3 (Closed) LER 50-282/98002; 50-306/98002 (1-98-02): Control Room Unfiltered Air Inleakage Found to be Excessive. This LER was part of the corrective action for the broader issue of control room habitability, as discussed in Unresolved Item (URI) 50-282/97015-04(DRP); 50-306/97015-04(DRP). This LER was discussed in Inspection Report 50-282/98003(DRP); 50-306/98003(DRP). The inspectors verified that the work was complete for the installation of new bottom seals on the control room to turbine floor doors, the control room to operator lounge door, the control room to records room door, and the control room chiller room doors. Also, magnetic seals had been installed on the control room to turbine building floor doors, and seals and frame gaskets had been installed on the control room chiller room doors.

The inspectors also reviewed the results of the gas trace inleakage testing that was performed subsequent to the maintenance on these doors and noted that the inleakage was below the design basis assumption for the loss-of-coolant accident configuration and just slightly below the limit for the main steamline break configuration. The inspectors discussed the proposed improved maintenance procedures for repair of the control room door seals with the system engineer. The procedures were to include periodic inspection and examination of the door seals to ensure that they were adequately performing their function. The inspectors found the corrective actions to be acceptable.

E8.4 <u>(Closed) LER 50-282/98003; 50-306/98003 (1-98-03)</u>: Routing of Containment Dome Fan Coil Unit Exhaust Dampers' Control Circuit Wiring Contrary to Configuration Described in USAR. This issue was previously discussed in Inspection Report 50-282/98003(DRP); 50-06/98003(DRP), Section E8.8. It involved the licensee's identification that some wiring for the dampers was routed as nonsafety-related, contrary to the description in the original Final Safety Analysis Report. The licensee had changed the USAR in 1994 to reflect the actual condition, but licensee quality services personnel questioned the safety evaluation that determined that the change was not an unreviewed safety question.

In February and March 1998, several discussions were held between the NRC and licensee on this issue. Both the licensee and NRC concluded that the change did not involve an unreviewed safety question because equipment failure of a magnitude that would defeat the system's safety function due to the wiring was not credible. On December 17, 1998, the licensee approved Safety Evaluation 340, "Fan Coil Unit Damper Control Circuit Configuration," Revision 1, in which it documented the conclusions and initiated action to update the USAR to reflect the actual condition.

E8.5 <u>(Closed) URI 50-282/98007-02(DRP); 50-306/98007-02(DRP)</u>: Potential Inoperability of MSIVs due to a Feedwater Line Break. This issue was previously discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section O2.1. In addition, the licensee provided additional details in LER 50-282/98005; 50-306/98005 (1-98-05), "Inoperability of Actuation Logic for Main Steam Isolation Valves in Certain Flooding Conditions from a Feedwater Line Break."

Since issuing the LER, the licensee performed additional analyses of feedwater line break events but was unable to change the original conclusion, as reported in the LER, that the ability of the MSIVs to close following a feedwater line break event could have been compromised due to flooding of electrical components. The licensee was also unable to show that the MSIVs were not necessary equipment for mitigation of the event. Thus, the condition that existed prior to the licensee's identification of the issue is considered a violation of TS Table 3.5.2.b, Item 5.a, which required that the MSIVs be operable and capable of performing their design function.

As discussed in the above referenced inspection report and the LER, the issue was licensee-identified. The condition was considered to be more than a minor concern but not a significant risk to the heath and safety of the public. The initial immediate corrective actions by the licensee were sufficient to restore operability. Long-term corrective actions were identified and were being accomplished in a time-frame commensurate with the safety significance of the issue. Therefore, this non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-282/98023-03(DRP); 50-306/98023-03(DRP)).

Licensee Event Report 1-98-05 associated with the issue will remain open pending completion of the long-term corrective actions to remove the flooding concern.

E8.6 <u>(Closed) Violation (VIO) 50-282/98007-08(DRP); 50-306/98007-08(DRP)</u>: Failure to Develop Testing Procedures for a Safety-Related Temporary Modification to the Cooling Water System. This violation was previously discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section E3.1. It involved the inspectors' identification that the licensee had installed a safety-related temporary modification, had left it in place for about 2½ years, and had not adequately completed preoperational testing of all of the components, nor had it developed periodic maintenance or testing procedures to demonstrate satisfactory inservice performance.

The licensee responded to the violation in a letter to the NRC dated July 6, 1998, in which it committed to develop and perform a surveillance procedure for the system by September 15, 1998. In addition, in the response letter, the licensee stated that they would transmit the results of a new revision to the safety evaluation for the temporary modification to the NRC.

The licensee developed the testing procedure as Revision 17 to SP 1151, "Cooling Water System Test," which was reviewed by the Operational Committee on November 2, 1998, and approved by the superintendent of mechanical systems/programs engineering on November 3. The actual test was completed on December 11, and was specified to be performed annually from then on. The test was conducted over three years after installation of the modification and almost three months later than the date the licensee committed to in its violation response. The system engineer responsible for the procedure revision stated that he did not realize that the licensee had committed to a particular completion date in its response letter. The fact that the testing was conducted later than the commitment was not safety significant because the system performed satisfactorily when tested.

Revision 1 to the safety evaluation for Temporary Modification 95T047, "Backup Compressed Air System for Cooling Water Strainer Backwash Valve Actuator," was reviewed by the Operational Committee on August 26, 1998, and approved by the general superintendent of engineering on September 1. The licensee provided a copy of the safety evaluation to the inspectors shortly after that date but failed to transmit it to the NRC Document Control Desk in accordance with its statement in the violation response letter. A licensing engineer stated that they had failed to enter the commitment to transmit the evaluation into the commitment tracking system. The inspectors discussed these two weaknesses in the commitment tracking program with the licensing engineers and plant management. The licensee later submitted the revised safety evaluation on December 22.

E8.7 (Closed) LER 50-282/98018; 50-306/98018 (1-98-18): Discovery that Surveillance Testing of Boric Acid Storage Tank Level Instrumentation Places Plant in a Condition Where a Single Failure Could Cause an Inability to Inject Concentrated Boric Acid. This issue was previously discussed in Inspection Report 50-282/98020(DRP); 50-306/98020(DRP), Section E8.2. At the time of that report, the LER had not yet been issued, but the corrective actions had already been completed. The inspectors reviewed the LER when issued and had no further concerns.

E8.8 (Closed) LER 50-282/98019; 50-306/98019 (1-98-19): Discovery that a Containment Penetration Piping Segment Could be Pressurized Beyond Its Design Basis. During the re-evaluation of selected piping penetrations, initially analyzed for NRC Generic Letter 96-06, “Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions,” it was discovered that a section of safety injection test piping in each unit could be subjected to a thermal-induced pressure transient which would cause the piping to exceed its allowed USAR stress values under design basis large-break loss-of-coolant accident (LOCA).

During the initial assessment of this portion of safety injection piping, the non-conservative assumption was made that during a large-break LOCA, the fluid inside of the piping would not heat up to peak containment temperature. A more in-depth evaluation revealed that the fluid could reach peak containment temperature and that the resulting thermally induced pressure transient would cause the pressure in the piping to increase to a value which would exceed its USAR allowed limit. The licensee performed an analysis on the safety injection test line using methodologies outlined in the USAR and the licensee’s engineering manual and determined that, even though the piping was stressed beyond the USAR limit, it would maintain its pressure boundary integrity.

The licensee discussed with the inspectors several options that were being considered to remedy the overpressure issue, but no specific decision had been made on how to proceed. The system engineer stated that the corrective action would be implemented by the end of each unit’s next refueling outage.

Since the NRC Office of Nuclear Reactor Regulation was conducting a review of all Generic Letter 96-06 issues and there were no immediate safety concerns associated with this issue, it is administratively closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Resin Transfer from the Spent Resin Tank (SRT) to a High Integrity Container (HIC)

a. Inspection Scope (IP 71750)

On January 12, 1999, the inspectors observed the transfer of spent resin from the SRT to a HIC located in the decontamination area of the auxiliary building. The transfer was an infrequently performed evolution and involved the potential for personnel overexposure. The following documents were reviewed as part of this inspection:

- Operating Procedure C21.1.3.7, "Spent Resin," Revision 11;
- System Prestart Checklist C21.1-6.35, "Discharging Spent Resin To Shipping Liner Using 122 Spent Resin Pump," Revision 11; and
- WO 9815125, "Transfer Resin From SRT to a HIC per C21.1.3.7."

b. Observations and Findings

The inspectors attended the pre-job briefing for the resin transfer operation. All personnel participating in the resin transfer operation were present. The briefing was thorough and included discussions of operator responsibilities, boundary guard duties and assignments, communications, expected radiation levels and dose rates, use of remote dosimetry, resin flowpaths, expected duration of the operation, contingency plans, and diverse level indications to determine when the HIC was full. The general superintendent of radiation protection and chemistry was present at the briefing and discussed management expectations concerning communications and procedural adherence.

The resin transfer operation was performed in accordance with Operating Procedure C21.1.3.7, Section 9.2. The inspectors noted good procedural adherence and communications throughout the operation. Boundary guards remained attentive to their duties and challenged personnel entering the resin transfer areas. Good dose reduction practices were observed including:

- The use of remote dosimetry. Personnel in high and locked high radiation areas were constantly monitored by a radiation protection specialist located in a nearby low dose waiting area. Other radiation protection specialists frequently surveyed general area radiation levels to minimize personnel exposure and ensure radiation area boundaries remained posted correctly.
- The use of remote monitoring cameras. Seven cameras were used to monitor critical areas, equipment, and personnel involved with the transfer operation. One of the cameras consisted of a 25-foot long remote visual probe inserted through a guide tube into the HIC. The probe provided a good, simple means of constantly monitoring the resin level inside the HIC and ensured the container was filled to capacity without overflowing.
- The use of portable lead shielding. Lead sheeting was used to cover the SRT discharge and the HIC recirculation lines. Lead plates mounted in portable,

vertical panels were also used to shield the person in charge of the resin transfer and operations personnel outside the decontamination area as well as personnel at the remote camera monitoring station.

Radiation dose rates during the actual resin transfer were approximately
2 Roentgens/hour on contact with the SRT discharge line lead shielding and
7 Roentgens/hour on the HIC resin liner.

c. Conclusions

Following a thorough pre-job briefing, the transfer of resin from the spent resin tank to a high integrity container was performed in an effective manner. Good radiation control practices were observed that minimized the radiation dose to personnel involved with the operation.

R2 Status of Radiation Protection and Chemistry Facilities and Equipment

R2.1 Main Steamline Radiation Monitors

a. Inspection Scope (IP 92903)

The inspectors reviewed the physical configuration, location, and function of four main steamline radiation monitors. There were four monitors located in the auxiliary building unit with one monitor on each steam line. The following documents were reviewed as part of this inspection:

- USAR, Section 7.5.2.19, "Steam Line Radiation Monitors," Revision 14;
- Offsite Dose Calculation Manual, Section 3.0, "Gaseous Effluents," Revision 14;
- Nonconformance Report 19983533, "Concern Over 1R-52 Being Installed 1-1/4" Farther Away From Steam Line Than Specified in Drawing";
- Technical Manual X-HIAW 2419-10, "Manual for Installation Operation Maintenance of Radiation Monitoring System E340028";
- SP 1243, "Radiation Monitoring Quarterly Source Test," Revision 2;
- SP 1027, "Radiation Monitoring Annual Calibration," Revision 17;
- SP 1783.6, "Victoreen Radiation Monitor Electronic Calibration," Revision 1;
- Drawing NF-38333-3, "Auxiliary Building - Steel - Unit 1 Impingement Walls," Revision E;
- Drawing NF-38334-2, "Auxiliary Building - Unit 1 & 2 Miscellaneous Framing," Revision E; and

- Drawing X-HIAW-2419-4, “7 Inch Lead Sampler Dimensional Outline,” Revision A.

b. Observations and Findings

On December 14, 1998, the inspectors noticed that steamline radiation monitor 1RE-803, “Loop 1R-52 12 Steam Generator Main Steam Loop Radiation Element,” was located farther from the main steam line than the other corresponding radiation monitors. The monitors detected gamma radiation and provided outputs to ERCS and steam release activity computers. During a primary-to-secondary leak with fuel damage, the monitors quantified the amount and rate of radioactive releases to the environment from the steam generator safety valves, power-operated relief valves, atmospheric steam dumps, and turbine-driven auxiliary feedwater pumps.

The inspectors measured the physical configuration of the monitors relative to the main steam piping and associated support components. No discrepancies were noted for monitors 1RE-801, 2RE-801, or 2RE-803. For 1RE-803, however, the inspectors noted that the gap between the top of the monitor and the steamline mirror insulation was 2½ inches. Drawing NF-38333-3 specifically required this dimension to have been verified in the field as 1¼ inches. Also, drawings NF-38334-2 and X-HIAW-2419-4 indicated that the distance between the centerlines of the main steamline and radiation detector should have been 26.6 inches. Using the measurements taken by the inspectors, the actual distance between centerlines was approximately 28.1 inches, an increase of 5.6 percent.

The inspectors contacted the system engineer and expressed concern that the increased distance might cause the steam release computer to underestimate the amount and rate of a radioactive release to the environment during an event. The system engineer acknowledged the concern and issued Nonconformance Report 19983533 to document the evaluation of concern. In the nonconformance report, the licensee reported its conclusion that the increased spacing between the steamline and the monitor had less than a one percent effect on the radiation field at the detector and was, therefore, negligible. The inspectors reviewed the calculations and had no additional concerns.

c. Conclusions

The inspectors identified slightly increased spacing between a main steamline and the associated radiation monitor. The licensee evaluated the actual configuration and determined that the increased spacing had a negligible effect on the radiation field at the detector. Therefore, calculations by the steam release activity computer that determined the amount and rate of radioactive releases to the environment during certain accidents would not have been significantly affected.

S1 Conduct of Security and Safeguards Activities (IP 71750)

During a routine search of a contractor’s truck, prior to the vehicle entering the protected area, security personnel discovered approximately one ounce of a controlled substance in the truck driver’s briefcase. The truck driver was denied access to the facility and detained until local police officers arrived to deal with the issue. Performance of the security force in this event was effective.

F1 Control of Fire Protection Activities (IP 71750)

During the 1M transformer fire discussed in Section O1.5 of this report, the plant fire brigade was activated. The brigade responded promptly with proper turnout gear. Hoses with foam application were brought to bear on the fire and it was extinguished fairly rapidly. The Town of Red Wing Fire Department was summoned, but the fire was essentially out by the time they arrived and they were not used. The fire brigade leader and fire marshal were in contact with the control room and decided not to have operators activate the 1M transformer water deluge system because the fire was not in the immediate area of the transformer and there were still energized fans and other equipment near the transformer. Overall, performance of the fire brigade was rapid and effective.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on January 14, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Sorensen, Plant Manager
K. Albrecht, General Superintendent Engineering, Electrical/Instrumentation & Controls
T. Amundson, General Superintendent Engineering, Mechanical
J. Goldsmith, General Superintendent Engineering, Generation Services
J. Hill, Nuclear Performance Assessment Manager
G. Lenertz, General Superintendent Plant Maintenance
J. Maki, Outage Manager
D. Schuelke, General Superintendent Radiation Protection and Chemistry
T. Silverberg, General Superintendent Plant Operations
M. Sleigh, Superintendent Security

INSPECTION PROCEDURES USED

IP 37551:	Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparations
IP 71750:	Plant Support Activities
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Follow up - Operations
IP 92902:	Follow up - Maintenance
IP 92903:	Follow up - Engineering
IP 92904:	Follow up - Plant Support
IP 93702:	Prompt Onsite Follow-up of Events

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Closed

50-306/97003 (2-97-03)	LER	Auto-Start of 22 Turbine-Driven Auxiliary Feedwater Pump on Undervoltage Signal and Entry Into TS 3.O.C for the Inoperability of Reactor Coolant Pumps When Buses 21 and 22 Were De-energized
50-282/97012; 50-306/97012 (1-97-12)	LER	Chemical and Volume Control System Malfunction Unanalyzed for Boron Dilution During Shutdown Modes of Operation
50-282/97023-03 (DRP)	VIO	Failure to Perform Two Steps in Reactor Physics Testing Procedure as Written
50-282/98001; 50-306/98001 (1-98-01) Original	LER	Leakage Through Redundant Control Room Steam Exclusion Dampers Found to Exceed Value Assumed in the HELB Analysis
50-282/98002; 50-306/98002 (1-98-02)	LER	Control Room Unfiltered Air Inleakage Found to be Excessive
50-282/98003; 50-306/98003 (1-98-03)	LER	Routing of Containment Dome Fan Coil Unit Exhaust Dampers' Control Circuit Wiring Contrary to Configuration Described in USAR

50-306/98005 (2-98-05)	LER	Turbine Trip/Reactor Trip From 22% Power During Planned Shutdown Operation
50-282/98007-08(DRP); 50-306/98007-08(DRP)	VIO	Failure to Develop Testing Procedures for a Safety-Related Temporary Modification to the Cooling Water System
50-282/98007-02(DRP); 50-306/98007-02(DRP)	URI	Potential Inoperability of Main Steam Isolation Valves Due to a Feedwater Line Break
50-282/98009; 50-306/98009 (1-98-09)	LER	Reactor Coolant Vent System Testing
50-282/98018; 50-306/98018 (1-98-18)	LER	Discovery That Surveillance Testing of Boric Acid Storage Tank Level Instrumentation Places Plant in a Condition Where a Single Failure Could Cause an Inability to Inject Concentrated Boric Acid
50-282/98019; 50-306/98019 (1-98-19)	LER	Discovery That a Containment Penetration Piping Segment Could be Pressurized Beyond its Design Basis
50-306/98023-01(DRP)	NCV	Failure to Use the Approved Procedure Change Process
50-282/98023-02(DRP)	NCV	Inadvertent Trip of Reactor Coolant Pump and Auto-Start of Turbine-Driven Auxiliary Feedwater Pump Due to Inadequate Procedure
50-282/98023-03(DRP); 50-306/98023-03(DRP)	NCV	Potential Inoperability of Main Steamline Isolation Valves Due to a Feedwater Line Break

Discussed

50-282/97015-04 (DRP); 50-306/97015-04 (DRP)	URI	Control Room Habitability
50-282/98001; 50-306/98001 (1-98-01) Supplement 1	LER	Leakage Through Redundant Control Room Steam Exclusion Dampers Found to Exceed Value Assumed in the HELB [High Energy Line Break] Analysis
50-282/98005; 50-306/98005 (1-98-05)	LER	Inoperability of Actuation Logic for Main Steam Isolation Valves in Certain Flooding Conditions From a Feedwater Line Break

LIST OF ACRONYMS USED

AMSAC	Anticipated Transient Without Scram Mitigation System Actuation Circuit
CFR	Code of Federal Regulations
°F	degrees Fahrenheit
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
DSS	Diverse Scram System
ERCS	Emergency Response Computer System
HELB	High-Energy Line Break
HIC	High Integrity Container
IP	Inspection Procedure
LER	Licensee Event Report
LOCA	Loss-of-Coolant Accident
LRO	Lead Reactor Operator
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
PORV	Power-Operated Relief Valve
psig	pounds per square inch - gauge
QA	Quality Assurance
RCGVS	Reactor Coolant Gas Vent System
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
rpm	revolutions per minute
SI	Safety Injection
SP	Surveillance Procedure
SRT	Spent Resin Tank
TCN	Temporary Change Notice
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order