July 2, 1998

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

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/98008(DRP); 50-306/98008(DRP)

Dear Mr. Wadley:

On June 18, 1998, the NRC completed an inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection.

During the 5-week period covered by this inspection, operations activities, including a significant power reduction and subsequent ascension, as well as a plant startup from cold shutdown conditions, were performed well. Maintenance and surveillance activities observed were also performed well except that there was unexpected interference between two jobs in the same area resulting in water entering a dewatered circulating water bay. Two operability evaluations performed by engineering personnel were reviewed. One was comprehensive and adequately justified interim operability of steam exclusion dampers. The other was weak in that a scenario that could have resulted in unnecessarily complicating the response to a reactor trip was not addressed. No violations were identified during the inspection.

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
Marc L. Dapas for

Geoffrey E. Grant, Director
Division of Reactor Projects

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

Enclosure: Inspection Report
50-282/98008(DRP);
50-306/98008(DRP)

See Attached Distribution

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

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State Liaison Officer, State
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State Liaison Officer, State
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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:	50-282/98008(DRP); 50-306/98008(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	May 12 through June 18, 1998
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Resident Inspector S. Thomas, Resident Inspector
Approved by:	J. W. McCormick-Barger, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Unit 1 and Unit 2
NRC Inspection Report 50-282/98008(DRP); 50-306/98008(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 5-week period of resident inspection.

Operations

- During the performance of power changes and relatively complex system alignments, the operators maintained good control of the plant and, when confronted with abnormal conditions, took prompt and conservative actions to restore the conditions to normal. (Section O1.1)

- The Unit 1 reactor startup from cold shutdown conditions and subsequent power ascension was performed in a deliberate and safe manner with no significant discrepancies noted. During the approach to criticality, the operators involved focused solely on the task at hand. (Section O1.3)

- Discrepancies in both the Technical Specifications and the Updated Safety Analysis Report regarding whether the steam line isolation logic used the Low T_{avg} or Lo-Lo T_{avg} setting were identified. The discrepancies had no affect on plant operations because surveillance test procedures included the proper setpoints and logic. In addition, operators were knowledgeable of the proper setpoints and inputs to the isolation logic. (Section O3.1)

Maintenance

- For the seven maintenance and surveillance activities observed, no significant problems were noted. Unexpected interference between one surveillance test and a concurrent maintenance activity in the same area resulted in water entering a dewatered circulating water bay. However, the interference could not have reasonably been predicted. (Section M1.1)

Engineering

- Several additional environmental qualification concerns with steam exclusion dampers were identified during corrective action activities for a finding associated with a control room damper. Licensee engineers completed a comprehensive evaluation which adequately justified interim operability until the completion of evaluations and corrective actions, where necessary. (Section E1.1)

- Although calculations eventually demonstrated that there should be sufficient indicated auxiliary feedwater (AFW) flow under worst case conditions to prevent operators from unnecessarily tripping reactor coolant pumps during a loss of feedwater accident with only one AFW pump available, the initial operability assessment of the effect of installing the AFW flow indication orifice plates backwards was weak because it did not address that issue. (Section E1.2)

Report Details

Summary of Plant Status

Unit 1 operated at or near full power until June 2, 1998, when power was reduced to approximately 15 percent to facilitate maintenance and testing activities. Unit 1 was returned to full power on June 4. On June 5, 1998, Unit 1 tripped from full power when a control rod dropped into the core. The unit was placed in cold shutdown during troubleshooting and repairs and was restarted on June 18. Unit 2 operated at or near full power for the entire inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Unit 1 Power Reduction for Cooling Tower 122 Inspection; Turbine Stop, Governor and Intercept Valve Testing; and Condenser Tube Cleaning at Power

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

On June 2, 1998, operators reduced power on Unit 1 to facilitate the structural inspection of the 122 cooling tower. While at the decreased power level of approximately 200 megawatts (MW) or 40 percent, turbine valve testing and condenser tube cleaning were performed. Power was subsequently reduced to about 15 percent so that personnel could safely enter a reactor coolant pump vault. A power increase to 100 percent was conducted on June 4, 1998. The inspectors observed most of the power changes. The documents reviewed by the inspectors to support this inspection were:

- Operating Procedure 1C1.4, "Unit 1 Power Operation," Revision 15;
- Special Operating Procedure D24.2, "Condenser Tube Cleaning At Power," Revision 16;
- Surveillance Procedure (SP) 1054, "Turbine Stop, Governor, and Intercept Valve Test," Revision 18; and
- Alarm Response Procedure C47012-0602, "12 RCP [Reactor Coolant Pump] Reservoir Hi/Lo Level," Revision 23.

b. Observations and Findings

The inspectors observed the Unit 1 power reduction evolution from the control room. The inspectors noted good use of formal communications, attentiveness to control board indications, conservative and controlled decision-making with regards to reactivity changes, consistently good acknowledgment of all alarm annunciators, and good supervisory oversight by the shift supervisor. Comments on observations of turbine valve testing in accordance with SP 1054 are contained in Section M1.1 of this report.

After the power reduction to about 200 MW, condenser tube cleaning was performed in accordance with Procedure D24.2. The evolution consisted of draining the condenser inner-pass and outer-pass piping, one at a time, and cleaning of the Amertap screens, condenser tube sheets, and condenser water boxes. The inspectors attended the pre-evolution briefing, observed portions of the activities from both the control room and locally, performed checks of the isolation cards, and performed a review of the work orders which authorized the maintenance. The inspectors noted good coordination during the evolution between the control room operators and the outplant operators draining and refilling the system. The inspectors observed that operators closely monitored circulating water and condenser parameters while the system was in an abnormal line-up due to the maintenance.

While the operators were returning the outer-pass piping back to service, they noted a leak on the gasket for the lower manway located on the inner-pass outlet piping. Prompt action was taken to secure the 11 cooling water pump, isolate and drain the inner-pass piping, replace the manway gasket, and return the inner-pass piping to service.

While operating at 200 MW, a “12 RCP Oil Reservoir HI/Low Level” alarm was received in the control room. This was a common alarm serving both the high and low setpoints for the two oil sumps on the 12 RCP. Upon receiving the alarm, the inspectors observed that the control room operators followed the guidance of the alarm response procedure which required increased monitoring of RCP oil temperatures and vibrations. After no adverse trends were observed, instrument and control technicians verified that the alarm was a valid signal for a low level in the lower reservoir. Comments on the subsequent corrective actions for the condition are discussed in Section M1.1 of this report.

In order for personnel to enter the RCP vault while maintaining their radiation dose as low as is reasonably achievable, operators reduced reactor power from about 40 percent to about 15 percent. The power reduction was accomplished in a controlled, deliberate manner. The concurrent reactivity effects of the power reduction, adding positive reactivity because of the power defect and adding negative reactivity because of xenon production, were carefully tracked by the reactor operator. The lead reactor operator adequately controlled the condenser activities and the transition from main to bypass feedwater regulating valves, while maintaining an overview of unit status. The inspectors observed that the lead reactor operator maintained a correct focus on plant operations, by deferring non-essential activities, while power changes were occurring. Unit 1 was subsequently returned to 100 percent power operation on June 4, 1998, with no discrepancies noted by the inspectors.

c. Conclusions

During the performance of power changes and relatively complex system alignments, the operators maintained good control of the plant and, when confronted with abnormal conditions, took prompt and conservative actions to restore the conditions to normal.

O1.2 Unit 1 Reactor Trip from Full Power

On June 5, 1998, Unit 1 tripped from full power when Control Rod G7 dropped into the core because of an electrical short which caused a blown fuse on its stationary gripper coil. The NRC conducted a special inspection of the trip and subsequent operator performance during the recovery actions. The results of that inspection were documented in Inspection Report 50-282/98010(DRS).

O1.3 Unit 1 Reactor Startup

a. Inspection Scope (IP 71707)

On June 17-18, 1998, Unit 1 was started up and the generator placed on-line. The inspectors observed portions of the reactor coolant system heatup, equipment realignments for power operation, withdrawal of the shutdown control rod banks, warming of the steam system, control rod withdrawal to criticality, and power ascension. The following procedures were reviewed as part of this inspection:

- Operating Procedure 1C1.2, "Unit 1 Startup Procedure," Revision 19;
- Operating Procedure C1A, "Reactivity Calculations," Revision 13;
- Operating Procedure C1B, "Appendix - Reactor Startup," Revision 6; and
- Operating Procedure 1C1.4, "Unit 1 Power Operation," Revision 15.

b. Observations and Findings

All of the operations observed by the inspectors for starting up the plant and placing the generator on-line were conducted in a careful and deliberate manner. No significant discrepancies were noted. For the approach to criticality, the inspectors conducted continuous observations in the control room. The shift supervisor gave each operator time to review the reactor startup procedure prior to the startup. The pre-evolution briefing, conducted by the shift manager, was adequate and included a complete review of all of the precautions. Duties of each individual member of the operations team were clearly designated. A few industry events associated with startup errors were discussed, although not in detail.

For the reactor startup, 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. Distractions were minimized and control room access was strictly controlled by the lead reactor operator. One of the reactor operators and a nuclear engineer performed independent inverse count rate calculations and they compared the predicted critical rod positions frequently. Criticality was achieved near the predicted point and was properly identified and recorded. Control room communications were usually formal and all annunciators were properly announced and assessed.

c. Conclusions

The Unit 1 reactor startup and power ascension was performed in a deliberate and safe manner with no significant discrepancies noted. During the approach to criticality, the operators involved focused solely on the task at hand.

O3 Operations Procedures and Documentation

O3.1 Editorial Errors in Technical Specifications (TS) and Updated Safety Analysis Report (USAR) Regarding Average Reactor Coolant System Temperature (T_{avg}) Logic

a. Inspection Scope (IP 92901)

The inspectors identified editorial errors in the TS and USAR and verified that the errors had no effect on plant operations. The inspectors reviewed the following documents as part of this inspection:

- TS Table 3.5-1, "Engineered Safety Features Initiation Instrument Limiting Set Points," Revision 44;
- TS Table 3.5-2B, "Engineered Safety Feature Actuation System Instrumentation," Revision 111;
- TS Table 4.1-1B, "Engineered Safety Feature Actuation System Instrumentation Surveillance Requirements," Revision 111;
- Basis for Technical Specification 3.5, "Instrumentation System," Revision 111;
- USAR Section 7.4.2.2.b, "Steam Line Isolation," Revision 14;
- USAR Table 7.4-1, "List of Reactor Trips & Causes of Actuation of Engineered Safety Features, Containment and Steam Line Isolation & Auxiliary Feedwater," Revision 12;
- USAR Figure 7.4-15, "Engineered Safety Feature Logic Diagram," Revision 1;
- USAR Section 14.5.5, "Rupture of a Steam Pipe," Revision 14; and
- SP 1002A, "Analog Protection System Calibration," Revision 22.

b. Observations and Findings

The T_{avg} instruments had both low and lo-lo logic setpoints. A low setpoint of $\geq$554 degrees Fahrenheit (°F) was used in feedwater line isolation logic and a lo-lo setpoint of $\geq$540°F was used in steam line isolation logic. The inspectors identified that Item 5 of TS Table 3.5-1 incorrectly stated that the steam line isolation setpoint was "High Steam Flow in a Steam Line Coincident with Safety Injection and Low T_{avg}" and the same table incorrectly stated that the limiting setpoint for Low T_{avg} was $\geq$540°F. Also, the TS Basis for TS 3.5 incorrectly stated in two places that the input for steam line isolation was Low T_{avg}. Item 5d of Table 3.5-2B and Item 5d of Table 4.1-1B, however, correctly stated that steam line isolation was on high steam flow and Lo-Lo T_{avg} with safety injection.

The inspectors reviewed the USAR and noted a similar error. Whereas, Section 7.4.2.2.b, Item 21 of Table 7.4-1, and Figure 7.4-15 all correctly stated that the input was Lo-Lo T_{avg}, Section 14.5.5 incorrectly stated that the input was Low T_{avg}.

The inspectors verified that the surveillance test procedures for calibration of the instruments included the proper setpoints, nomenclature, and logic. The inspectors also interviewed several operations personnel and verified that there was no confusion on their part regarding the setpoint for steam line isolation. Thus, the discrepancies had only minor safety significance.

The inspectors informed a licensing engineer of the editorial discrepancies so that they could be addressed in a future TS amendment request and USAR revision. The inspectors also discussed the findings with the project manager in the NRC Office of Nuclear Reactor Regulation. Due to the minor nature of the errors, the project manager stated that correcting the TS could be postponed until the licensee's submittal of Improved Standardized TS, unless other changes to the same table were submitted earlier.

Technical Specifications, including proper limiting safety system settings, were required to be submitted in accordance with 10 CFR 50.36. Although the numerical setting of $\geq$540°F submitted by the licensee for TS Table 3.5-1 was correct, the nomenclature for the setting was incorrect. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

The inspectors identified discrepancies in the TS and USAR regarding whether the steam line isolation logic used the Low T_{avg} or Lo-Lo T_{avg} setting. The discrepancy had no effect on plant operations because surveillance test procedures included the proper setpoints and logic. In addition, operators were knowledgeable of the proper setpoints and inputs to the isolation logic.

O7 Quality Assurance in Operations

O7.1 Management Changes Affecting the Quality Assurance Organization (IP 71707)

On June 8, 1998, the licensee announced organizational and management changes to be effective on June 15. Mike Wadley, Vice President, Nuclear Generation, was named to the newly created position of President, NSP Nuclear Generation. Ed Watzl, President, NSP Generation, was named to the newly created position of Executive Vice President. On June 16, 1998, Mr. Wadley informed the NRC that the quality services department would be reporting to him. Previously the department reported to the president, NSP Generation, a position that was deleted in the organization change. The licensee was in the process of determining whether this change in its Operational Quality Assurance Plan was a reduction in commitment.

O8 Miscellaneous Operations Issues (IPs 92700, 92901)

O8.1 (Closed) Violation (VIO) 50-306/97006-01(DRP): Inadequate Procedure for Filling and Venting the Reactor Coolant System; and

Closed) VIO 50-282/97011-01(DRP); 50-306/97011-01(DRP): Nine Examples of Procedures of a Type Not Appropriate to the Circumstances.

The two violations represented ten cases where operating or maintenance procedures were inadequate, either because they did not contain necessary information, or because the information they did contain was inaccurate or misleading. The inspectors reviewed the licensee's response to the violations contained in letters to the NRC dated May 30, 1997, and August 25, 1997. For each specific example, the inspectors verified that the procedure had been revised to correct the discrepancy. The inspectors also verified, were applicable, that similar procedures for the opposite train or unit had been corrected.

In addition to correcting the specific procedure problems, the licensee instituted a comprehensive procedure improvement program. Details of that program have been discussed in previous inspection reports and public meetings, including the recent meeting for the Systematic Assessment of Licensee Performance held on May 19, 1998.

O8.2 (Closed) Licensee Event Report (LER) 50-282/97008 (1-97-08): Unit 1 Reactor Trip Caused by Electrical Ground in Rod Control System. This event was previously discussed in Inspection Report 50-282/97011(DRP); 50-306/97011(DRP), Section O3.1. The cause of the trip was a short to ground in one of the wires to a control rod stationary gripper coil inside the connector on the cable near the reactor head. The connector was sent to an independent laboratory for analysis. During this inspection period, another Unit 1 trip occurred from what appeared to be a similar failure on another control rod stationary gripper coil. The cable for that rod and two others were sent to another laboratory for analysis. The licensee will issue LER 1-98-08 describing the cause and corrective actions for the latest trip. The new LER and its associated corrective actions will also include the information learned from the followup associated with the event described in LER 1-97-08. Since the corrective actions for the second trip will include any remaining actions for the first trip, the first LER is closed to avoid duplication.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance Testing and Maintenance Observations

a. Inspection Scope (IPs 61726, 62707)

The inspectors witnessed all or major portions of the following maintenance and surveillance testing activities. Included in the inspection was a review of the surveillance procedures (SPs) and work orders (WOs) listed below, as well as the appropriate USAR sections regarding the activities. The inspectors verified that the surveillance tests reviewed met the requirements of the TS.

- WO 9804341, “Rebuild 11 Circulating Water Traveling Screen”;
- WO 9805103, “Perform Control Rod Drive Mechanism Timing Tests (Hot)”;
- SP 1032B, “Safeguards Logic Test At Power - Train B,” Revision 5;
- SP 1032C, “Safeguards Boric Acid Logic Test,” Revision 3;
- SP 1054, “Turbine Stop, Governor, and Intercept Valve Test,” Revision 18;
- SP 1102, “11 Turbine-Driven AFW [Auxiliary Feedwater] Pump Monthly Test,” Revision 62; and
- SP 1202, “Fire Pump(s) Test Fire Protection System,” Revision 11.

b. Observations and Findings

- On May 27, 1998, the inspectors observed the pre-job briefing for and the performance of testing of the automatic actuation and capacity of the three fire protection pumps in accordance with SP 1202. Coincidently, maintenance workers were preparing to enter the 11 circulating water intake bay, which had been isolated with stop logs and dewatered, for rebuilding of the 11 circulating water traveling screen in accordance with WO 9804341. The workers noted that water was flowing into the bay and the inspectors pointed out that the water was coming from the fire protection system test header discharge piping, which discharged on the other side of the stop logs. Some of the fire protection water was discharging over the stop logs into the dewatered bay.

  The inspectors interviewed operations, maintenance, and work planning personnel involved with SP 1202 and WO 9804341 to determine if there was a work control problem that allowed two conflicting jobs to be scheduled at the same time. The inspectors determined that the conflict would have been hard to predict.

  Drawing NF-39261-2, “Screenhouse Fire Protection and Screen Wash Piping,” Revision J, showed that the fire protection test header discharged at least 10 feet away from the stop logs. Without a close inspection of the exact configuration of the piping, it was not obvious that some of the test header water would be discharged over the stop logs. No one interviewed remembered the fire protection discharge header ever being used while the 11 circulating water bay was dewatered, so there was no previous experience to draw from. Thus, the inspectors concluded that there had not been a significant breakdown in the maintenance planning process.

  The amount of water that was discharge over the stop logs was not a significant personnel hazard, even if the workers had been in the bay, because of the relatively large bay volume and the dewatering pumps that were installed.

- For turbine stop, governor, and intercept valve testing in accordance with SP 1054, the inspectors observed portions of both the control room operations and local activities. The inspectors noted that the pre-evolution briefing was adequate and that the evolution was conducted in a safe and controlled manner. The inspectors observed that the operation of the valves being tested was smooth, with no evidence of binding or leakage.

  The surveillance was completed satisfactorily except for a position indication limit switch for the 1B reheater stop valve being out-of-alignment. The inspectors noted that, when this problem was encountered during the performance of surveillance testing, the evolution was temporarily stopped, the 1B reheater stop valve position was verified by location indication to be shut, and a work order was prepared to authorize adjustment of the limit switch.

- As discussed in Section O1.1 of this report, a reactor coolant pump low oil level condition was confirmed on the 12 RCP. A power reduction to approximately 15 percent was performed and a work order was prepared with instructions for entering containment to inspect the RCP and adding oil to the lower oil reservoir. The inspectors interviewed the system engineer who supervised the corrective actions and he reported that there was slight leakage from a drain valve fitting, which was corrected by tightening the fitting; slight weepage from a sight glass, which could not be corrected with the pump running; and that 2½ gallons of oil were added to clear the low level alarm. Additionally, he reported that there was no large build-up of oil present and that there was approximately 2½ quarts of oil in the flash pan, which was wiped up. The rest of the oil would have drained to a collection tank.

c. Conclusions

For the seven maintenance and surveillance activities observed, no significant problems were noted. Unexpected interference between one surveillance test and a concurrent maintenance activity in the same area resulted in water entering a dewatered circulating water bay. However, the interference could not have reasonably been predicted.

M8 Miscellaneous Maintenance Issues (IPs 92700, 92902)

M8.1 (Closed) LER 50-306/98002 and LER 50-306/98002, Supplement 1 (2-98-02): Defect in Primary System Pressure Boundary Observed on the Motor Tube Base of Part Length CRDM [Control Rod Drive Mechanism] Housing. This event was previously discussed in Inspection Report 50-282/97003(DRP); 50-306/97003(DRP), Sections O1.3 and M1.2. The licensee supplemented the original LER on May 22, 1998, with the results of an analysis performed by Westinghouse and reported in WCAP-15054, "Metallurgical Investigation and Root Cause Assessment of Part Length CRDM Housing Motor Tube Cracking at Prairie Island Nuclear Generating Plant Unit 2." The licensee submitted the report to the NRC in a separate letter dated May 15, 1998.

The conclusion reported in the analysis was that the flaw was a weld fabrication defect with no evidence of service-induced growth. The flaw was most likely caused by contamination introduced in the welding process. No other similar defects were identified in the other part length CRDMs removed from Prairie Island Unit 2 nor on any of the 60 part length CRDMs removed from other plants. Therefore, the problem was considered an isolated case. All of the part length CRDMs were removed from Unit 2 and the licensee intended to either inspect or remove the Unit 1 part length CRDMs in the next refueling outage. In the interim, the enhanced leak monitoring measures discussed in the LER remained in effect for Unit 1. The NRC Office of Nuclear Reactor Regulation was continuing to review the generic aspects of this issue.

III. Engineering

E1 Conduct of Engineering

E1.1 Steam Exclusion Dampers Not Environmentally Qualified (EQ)

a. Inspection Scope (IP 92903)

On June 22, 1998, the inspectors were informed that licensee engineers had identified several steam exclusion dampers or components located in areas that would potentially be harsh environments following a steam line break accident. Some components in the dampers and damper actuation equipment were not qualified for those conditions. The inspectors reviewed the licensee’s operability evaluation of the dampers and proposed corrective actions.

b. Observations and Findings

As discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section E8.1, and LER 50-282/98006; 50-306/98006 (1-98-06), the licensee discovered a damper in the control room ventilation system that was not EQ and was located in a potentially harsh environment. This issue was considered a non-cited violation. One of the corrective actions described in the LER was for the licensee to inspect all other steam exclusion dampers to assure that the non-EQ equipment was not located in potentially harsh environments. While performing that inspection, licensee engineers identified and evaluated several discrepancies.

- Dampers CD-34185 and CD-34186, which isolated the Unit 1 low level waste gas storage tank area, were located in a potentially harsh environment. Licensee engineers determined that steam exclusion in that area was not required and were in the process of downgrading the dampers.

- Dampers CD-34145 and CD-34142, which isolated control room outside air, had electrical boxes containing fuses and terminal strips located in potentially harsh environment areas. Dampers CD-34187 and CD-34188, which isolated portions of the auxiliary building, had most of their components located in potentially harsh environment areas. Also, eight dampers which isolated the auxiliary feedwater pumps rooms and safeguards battery rooms had some or most of their components located in the nonsafeguards bus rooms which had never been evaluated for post-accident environmental conditions. For all of those dampers, licensee engineers performed operability assessments, including some component testing, which indicated that the dampers would perform satisfactorily during high energy line break accidents. Operability was based on the following:

- actuation of the dampers to the post-accident positions would take place when temperatures in the area reached 114°F., which was still considered a mild environment;

- in all cases, the actuation signal would be sealed in by relays located in a mild environment;

- all dampers would fail to the desired post-accident positions on a loss of electrical power or instrument air;

- degradation of the mechanical components of the dampers subject to thermal damage would not cause the dampers to reopen or leak excessively; and

- complete degradation of all non-metallic components of the solenoid valves which ported instrument air to the dampers would not result in enough air leakage to actuate the dampers to the open position.

The last point was verified by testing solenoid valves with all non-metallic components removed and verifying that outlet port leakage was not of a quantity or pressure high enough to inadvertently open the dampers.

Licensee Non-Conformance Report (NCR) 19981105 documented the licensee's findings, operability evaluation, testing, and planned corrective actions for these issues. The inspectors reviewed the NCR and found that it was comprehensive and contained adequate information to justify interim operability until corrective actions were completed.

A total of 15 out of a population of 26 steam exclusion dampers had at least some EQ concerns. The licensee was still evaluating whether the discrepancies placed the components outside of the design basis. The status of these issues will be reviewed again during the inspectors' next review of LER 1-98-06.

c. Conclusions

The licensee identified several additional EQ concerns with steam exclusion dampers during corrective action activities for a finding associated with a control room damper. Licensee engineers completed a comprehensive evaluation which adequately justified interim operability until the completion of evaluations and corrective actions, where necessary.

E1.2 Evaluation of the Effect of Improperly Installed AFW Flow Instrument Orifice Plates on the Use of Emergency Operating Procedures (EOPs)

a. Inspection Scope (IP 92903)

The inspectors reviewed engineering calculations to determine if there was a concern that operators could be led to take unnecessary actions, while following EOPs, due to the Unit 2 AFW flow instrument orifice plates being installed backwards. The following documents were reviewed during this inspection:

- Calculation ENG ME-366, "Minimum Expected AFW Flow Indication to Unit 2 Steam Generators at 1077 psig [pounds per square inch-gauge]," dated May 28, 1998;

- Calculation ENG ME-367, "Determination of Expected AFW Flow Rates for Operating Procedures," dated May 22, 1998;

- NCR 19980890, "Unit 2 Degraded AFW Flow Indication as a Result of Orifices Being Installed Backwards"; and

- Functional Restoration Guideline 2FR-H.1, "Response to Loss of Secondary Heat Sink," Revision 9.

b. Observations and Findings

This issue was previously discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section M3.3. Because AFW flow detector orifice plates were installed backwards, indicated flow would be expected to be less than actual flow. The inspectors raised the concern that, if AFW flow indicated less than 200 gallons per minute (gpm) when it was actually greater than 200 gpm, an unnecessary entry into 2FR-H.1 during certain EOP scenarios could result. The guideline contained instructions to stop the RCPs to limit the heat input to the steam generators. The accident of most concern was a loss of feedwater with a concurrent loss of one of the two AFW pumps. Decay heat removal via natural circulation without RCPs was within the design basis of the plant, but it would complicate the operators' response.

During this inspection period engineering calculations ENG-ME-366 and 367 were performed, reviewed, and approved by licensee engineering personnel. The engineers concluded that worst case expected AFW flow indication with the flow orifices installed backwards was 202 gpm. Thus, unnecessary entry into 2FR-H.1 would not occur. The inspectors reviewed the calculations and identified no concerns with the licensee's conclusions.

The licensee's initial operability assessment of the effects of the AFW flow orifices being installed backwards was contained in NCR 19980890. That assessment included a review of the effects of operators setting indicated AFW flow to values specified in the EOPs, resulting in higher than specified actual flows. No adverse effects during EOP activities were identified. However, the NCR did not address the possibility that specified indicated flow might not be obtainable because of the orifice errors. The operability assessment was weak in that it failed to consider that a potential entry into 2FR-H.1 might result. However, the latter calculations, performed because of the inspectors' concerns, indicated that there would still be a small margin of indicated flow above the 2FR-H.1 entry condition.

c. Conclusions

Although calculations eventually demonstrated that there should be sufficient indicated AFW flow under worst case conditions to prevent operators from unnecessarily tripping reactor coolant pumps during a loss of feedwater accident with only one AFW pump available, the initial operability assessment of the effect of installing the AFW flow indication orifice plates backwards was weak because it did not address that issue.

E2 Engineering Support of Facilities and Equipment

E2.1 Review of USAR Commitments (IPs 37551, 92903)

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected and used the USAR as an engineering/technical support basis document. The inspectors compared plant practices, procedures, and/or parameters to the USAR descriptions as discussed in each section. The inspectors verified that the USAR wording was consistent with the observed plant practices, procedures, and parameters. One minor editorial discrepancy was identified in USAR Section 14.5.5 as discussed in Section O3.1 of this report.

E8 Miscellaneous Engineering Issues (IPs 92700, 92903)

E8.1 (Closed) LER 50-282/97001; 50-306/97001 (1-97-01): Auxiliary Building Crane Protective Features Defeated by Wiring Errors. This issue was previously discussed in Inspection Report 50-282/97002(DRP); 50-306/97002(DRP), Section O1.2. The finding was treated as a Non-Cited Violation in that report. The inspectors reviewed spent fuel cask handling procedures to ensure that notes were added to describe the new labeling and key functions on the crane control transmitter box and that the procedures were revised to require the crane operator to check the fuel pool enclosure roof slot limit switch function prior to critical lifts. Other corrective actions, as specified in the LER, were verified by discussions with the cognizant members of the licensee engineering staff.

E8.2 (Closed) LER 50-282/97010 (1-97-10): Failure to Evaluate the Condition of a Residual Heat Removal Pump When the Vibration Level During a Surveillance Test Was Recorded at the Alert Level. This issue was previously discussed in Inspection Report 50-282/97015(DRP); 50-306/97015(DRP), Sections M7.1 and M8.7. The finding was treated as a Non-Cited Violation in that report. The inspectors verified by review of licensee documents that the corrective actions discussed in the LER had been completed. A memorandum was sent on August 24, 1997, to all engineering personnel emphasizing the need to follow the administrative work instructions for system turnovers between system engineers. Training on American Society of Mechanical Engineers inservice testing requirements was given to mechanical system engineers on October 3 and October 8, 1997.

E8.3 (Closed) LER 50-282/97018; 50-306/97018 (1-97-18): Failure to Test the Auto-Start Feature of the Control Room Ventilation System Air Handlers Due to Procedure Deficiency. This issue was previously discussed in Inspection Report 50-282/97023(DRP); 50-306/97023(DRP), Section E3.1. The finding was treated as a Non-Cited Violation in that report. The inspectors verified by review of licensee documents that SP 1083, "Unit 1 Integrated SI [Safety Injection] Test with a Simulated Loss of Offsite Power," Revision 24, and SP 2083, "Unit 2 Integrated SI Test with a Simulated Loss of Offsite Power," Revision 21, contained changes to verify the automatic start of the control room air handler fans on an SI during the refueling outage surveillance tests.

E8.4 (Open) LER 50-282/98006; 50-306/98006 (1-98-06): Control Room Vent Outside Air Equipment Qualification. Additional licensee findings discovered during corrective actions for this LER were discussed in Section E1.1 of this report. Resolution of the additional concerns will be included in the closing of this LER in a future inspection.

E8.5 (Closed) Unresolved Item (URI) 50-282/98007-07(DRP); 50-306/98007-07(DRP): Possible Failure to Perform an Evaluation in Accordance with 10 CFR 50.59. This issue was previously discussed in Inspection Report 50-282/98007(DRP); 50-306/98007(DRP), Section E3.1. The inspectors reviewed Addendum 1 to Safety Evaluation 95T047, "Backup Compressed Air Supply for Cooling Water Strainer Backwash Valve Actuator," which contained an evaluation of all failure modes of the backup air bottle regulator. The licensee's conclusion, documented in Addendum 1, was that the temporary modification did not involve an unreviewed safety question. The inspectors had no further concerns with the safety evaluation.

IV. Plant Support

P2 Status of Emergency Preparedness Facilities, Equipment, and Resources

P2.1 Temporary Inoperability of Public Alert Sirens (IP 92904)

On June 1, 1998, the licensee reported in accordance with 10 CFR 50.72 that about 39 percent of the public alert sirens surrounding the plant had been lost due to weather-related power interruptions on or about 11:05 p.m. on May 30, 1998. Most of the sirens were restored by 12:18 a.m. on May 31. The licensee did not become aware of the extent of the losses until June 1. Routine siren testing conducted on June 3, 1998, indicated that only four sirens were inoperable at that time and all were returned to service by June 4. The licensee was in the process of determining which electrical power lines fed which sirens in order to be able to better predict which sirens would be lost during electrical outages. This issue will be reviewed in the next NRC emergency preparedness inspection.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Potential Inadequate Separation Between Fire Areas (IP 92904)

On May 26, 1998, the licensee reported, in accordance with 10 CFR 50.72, that it had identified some areas in which separation between fire areas may not have met 10 CFR Part 50, Appendix R requirements. The issues were identified during licensee self-assessments in preparation for a planned NRC Fire Protection Functional Inspection. The licensee intended to conduct additional evaluations of the findings and issue LER 2-98-03 to report its findings. The LER will be assigned to the NRC Fire Protection Functional Inspection Team for followup.

F8 Miscellaneous Fire Protection Issues (IP 92904)

F8.1 (Closed) VIO 50-282/97011-05(DRP): Failure to Provide Safe Shutdown Emergency Lighting for Access and Egress Routes to the Safeguards Bus No. 15 Room. This issue was previously discussed in Inspection Report 50-282/97011(DRP); 50-306/97011(DRP), Section M3.3. The inspectors reviewed the licensee's corrective actions, including the revision of surveillance test procedures and the installation of a new emergency light illuminating the access and egress routes to the Safeguards Bus No. 15 room. The corrective actions were found to be complete and the inspectors had no additional concerns. The inspectors also noted that the licensee installed 13 additional emergency lights in various location throughout the plant as a result of findings during recent fire protection self-assessment efforts. In addition, the licensee was considering performing darkened condition tests to verify the adequacy of emergency lighting.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 18, 1998. 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, Manager Quality Services
G. Lenertz, General Superintendent Plant Maintenance
R. Lindsey, General Superintendent Safety Assessment
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 71750	Plant Support Activities
IP 92700:	Onsite Follow-up of Written Reports of Non-routine 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

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

None.

<u>Closed</u>

50-282/97001 (1-97-01) 50-306/97001	LER	Auxiliary Building Crane Protective Features Defeated by Wiring Errors
50-306/97006-01(DRP)	VIO	Inadequate Procedure for Filling and Venting the Reactor Coolant System
50-282/97007-07(DRP) 50-306/97007-07(DRP)	URI	Possible Failure to Perform an Evaluation in Accordance with 10 CFR 50.59
50-282/97008 (1-97-08)	LER	Unit 1 Reactor Trip Caused by Electrical Ground in Rod Control System
50-282/97010 (1-97-10)	LER	Failure to Evaluate the Condition of a Residual Heat Removal Pump When the Vibration Level During a Surveillance Test Was Recorded at the Alert Level
50-282/97011-01(DRP) 50-306/97011-01(DRP)	VIO	Nine Examples of Procedures of a Type Not Appropriate to the Circumstances
50-282/97011-05(DRP)	VIO	Failure to Provide Safe Shutdown Emergency Lighting for Access and Egress Routes to the Safeguards Bus No. 15 Room
50-282/97018 (1-97-18) 50-306/97018	LER	Failure to Test the Auto-Start Feature of the Control Room Ventilation System Air Handlers Due to Procedure Deficiency
50-306/98002 (2-98-02) Supplement 1	LER	Defect in Primary System Pressure Boundary Observed on the Motor Tube Base of Part Length CRDM Housing

Discussed

50-282/98006 (1-98-06) 50-306/98006	LER	Control Room Vent Outside Air Equipment Qualification

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EOP	Emergency Operating Procedure
EQ	Environmentally Qualified
°F	Degrees Fahrenheit
gpm	Gallons Per Minute
IP	Inspection Procedure
LER	Licensee Event Report
MW	Megawatts
NCR	Non-Conformance Report
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
psig	Pounds Per Square Inch-Gauge
RCP	Reactor Coolant Pump
SI	Safety Injection
SP	Surveillance Procedure
T_{avg}	Average Reactor Coolant System Temperature
TS	Technical Specifications
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order