November 18, 1998

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

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/98018(DRP); 50-306/98018(DRP)

Dear Mr. Wadley:

On October 22, 1998, the NRC completed an inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection.

During the 6-week period covered by this inspection, plant operations, engineering and maintenance activities, surveillance testing, and plant support efforts were performed well. An exception to this occurred when a radiation protection specialist performed a contamination survey of the shield building special ventilation system at the wrong point in the surveillance procedure, causing entry into two limiting conditions for operation statements without the knowledge of control room personnel. This was the second safety-related shield building ventilation system procedure problem in 14 days. These two recent problems indicate the need for comprehensive corrective actions to ensure that the good procedure adherence practices observed over the last several months in the operations department are carried over to other plant departments.

No violations of NRC requirements were identified during this inspection period.

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
Michael Kunowski for

Anton Vegel, Chief
Reactor Projects Branch 7

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

Enclosure: Inspection Report
50-282/98018(DRP);
50-306/98018(DRP)

<u>See Attached Distribution:</u>

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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Northern States Power Company
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State Liaison Officer, State of Minnesota
State Liaison Officer, State of Wisconsin
Tribal Council, Prairie Island Dakota Community

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REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	50-282/98018(DRP); 50-306/98018(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	September 11 through October 22, 1998
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Senior Resident Inspector (acting) S. Thomas, Resident Inspector
Approved by:	A. Vegel, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Unit 1 and Unit 2
NRC Inspection Report 50-282/98018(DRP); 50-306/98018(DRP)

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Operations activities observed during the inspection period were conducted effectively, in accordance with plant procedures. (Section O1.1)

- The inspectors observed a senior reactor operator, who was directing new fuel handling operations, become involved in hands-on tasks instead of maintaining a supervisory role. Implementation of a new, non-outage work control center has resulted in fewer control room distractions. (Section O1.1)

- Operators reduced Unit 2 power to 40 percent to support turbine valve testing and subsequently returned it to 100 percent in a controlled and deliberate manner. Expected deviations of neutron flux distributions from the target band were handled well by operators. (Section O1.2)

Maintenance

- All the routine maintenance activities and surveillance tests observed by the inspectors were conducted well, utilized safe work practices, and demonstrated good communication and coordination between the control room and workers performing the work. Proper actions were taken when the inspectors identified that packing gland leakage could have caused the partial loss of safety-related, turbine-driven auxiliary feedwater pump bearing temperature monitoring capabilities. (Section M1.1)

- The 18-month preventative maintenance for the D5 emergency diesel generator was performed in a satisfactory manner. The quality control department established adequate hold points at appropriate steps during the maintenance activities. Foreign material controls were properly applied. The inspectors noted a minor inconsistency between the D5 operating procedures and the remote alarm response procedure concerning crankcase overpressure situations. (Section M1.2)

- Work control and procedural adherence control problems were evident when a radiation protection specialist performed a shield building special ventilation system (SBSV) contamination survey without the control room having entered the applicable Technical Specification Limiting Condition for Operation statements. This was the second problem associated with safety-related SBSV work in 14 days. (Section M1.3)

Engineering

- The licensee's probabilistic risk assessment (PRA) staff worked closely with planning personnel and routinely participated in work planning and configuration control decisions. The inspectors noted two instances where PRA analysis influenced work scheduling so as to minimize the risk effects of out-of-service equipment. Adequate steps were being taken to address the current limitations of the PRA model used for Prairie Island Units 1 and 2. (Section E2.2)

Plant Support

- The annual medical emergency drill and the spent fuel pool drill were conducted well. The participants demonstrated their ability to perform the required actions to mitigate the consequences of each event. (Section P1.1)

Report Details

Summary of Plant Status

Unit 1 operated at full power for the entire inspection period. Unit 2 power was reduced to about 40 percent on September 19-20, 1998, to perform main condenser and Amertap system maintenance and turbine valve testing. During the power reduction, axial flux distribution (ΔI) went out of the target band. Unit 2 returned to full power operation on September 22 and remained there for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (IPs 71707, 92901)

The inspectors conducted frequent reviews of plant operations. The reviews included observations of control room evolutions, shift turnovers, pre-job briefings, communications, control room access management, logkeeping, control board monitoring, and general control room decorum. Updated Safety Analysis Report (USAR), Section 13, "Plant Operations," Revision 15, was reviewed as part of the inspection.

b. Observations and Findings

- The inspectors accompanied a Unit 1 control room operator and a turbine building operator during their inspection of the 4.16-kilovolt (kV) safeguards busses in accordance with Surveillance Procedure (SP) 1322. The newly qualified turbine building operator performed SP 1322 for the first time. The inspectors witnessed the operator stopping on two occasions to contact the control room and request clarification on steps contained in the SP. The operator subsequently completed the surveillance with no discrepancies.

  The inspectors identified a minor writer's guide deviation in SP 1322. Step 7.16 did not print the name of the breaker to be checked in bold print as described in H14, "Procedure Writer's Guide," Revision 8, Step 4.6.4.I.2. The inspectors brought the minor discrepancy to the attention of the Unit 1 shift supervisor who submitted procedure change request 19981645 to correct the discrepancy.

- The inspectors accompanied a Unit 2 turbine building operator during the inspection of the 4.16-kV safeguards busses in accordance with SP 2322. As the result of using self-checking techniques, the operator realized that the panel 2R nameplate data did not match the information stated in Step 7.34 of the surveillance procedure. The operator examined other Unit 2 non-safeguards equipment bus rooms to be sure he was verifying as closed the correct relay knife switches as required by Step 7.34. After the operator verified the correct switches were closed, he informed the Unit 2 shift supervisor of the discrepancy. The Unit 2 shift supervisor subsequently submitted procedure change request 19981646, to revise Step 7.34, to include the correct panel name.

- The inspectors observed operations personnel receiving, inspecting, and storing new fuel in accordance with Work Order (WO) 9807036, "PN 2110 Receive New Fuel for Cycle 19 Per D9," and maintenance procedure "Nuclear Fuel Technical Evaluation," Revision 28. A senior reactor operator (SRO) directed fuel handling operations, and a nuclear engineer and an intern engineer performed independent verifications of fuel storage locations in the dry pool and evaluated fuel assemblies. Four non-licensed operators were the crane operators and shipping cask handlers. The inspectors noted that independent verifications were properly performed and the fuel transfer log was correctly maintained for movement of new fuel between the shipping casks and the dry spent fuel pit storage locations. The inspectors verified that requirements for fuel assembly orientation during dry storage and for contamination surveys were also met.

  During movement of fuel assembly W79, the inspectors observed the SRO performing work tasks, potentially impacting his ability to supervise the fuel handling activities. Specifically, the SRO was observed helping workers return shipping cask outrigger members to their storage location, installing the respective outrigger member locking pins, and using a pneumatic socket wrench to install the closure flange bolts on a shipping cask cover. The inspectors discussed this concern with the SRO, the nuclear engineer, and the Unit 1 and Unit 2 shift supervisors who acknowledged the concern. Subsequently, supervisors limited their involvement in physical work during fuel handling operations.

  The inspectors observed operations personnel receiving, inspecting, and storing new fuel again a week later. Proper supervisory control was evident during the receipt, inspection, and storage of four new fuel assemblies. The inspectors also verified that the rigging used for new fuel handling operations met procedural requirements.

- The inspectors reviewed licensee implementation of a new, non-outage work control center (WCC) located on the main turbine floor outside of the control room. In the past, a WCC was established only during outage periods. The purpose of the non-outage WCC was to serve as the first point of contact for operational needs associated with assigned work. The WCC was staffed by experienced operations department personnel. The licensee expected the WCC to eliminate distractions from the control room and provide greater consistency and control in implementation of the work process.

  Since the implementation of the WCC, the inspectors observed WCC personnel present at morning shift briefings. The WCC was actively involved in work processes, resulting in noticeably fewer distractions in the control room. In particular, the functioning of the WCC reduced the administrative burden on the control room shift supervisors, allowing them to focus their attention on other control room personnel and plant operations. In addition, the general superintendent of operations directed operators to meet daily with WCC personnel for mid-shift briefings. This was a good work control initiative. The inspectors have subsequently observed good coordination of work scheduling and work package processing between the WCC and the control room.

c. Conclusions

Operations activities observed during the inspection period were conducted well. On one occasion, however, inspectors observed a senior reactor operator who was directing new fuel handling operations become involved in work activities instead of maintaining a supervisory role. Implementation of a new, non-outage work control center has resulted in fewer control room distractions.

O1.2 Unit 2 Power Reduction and Ascension

a. Inspection Scope (IP 71707)

The inspectors observed major portions of control room activities during a Unit 2 power reduction to about 40 percent on September 19-20, 1998, and the subsequent return to full power operation on September 22. The power reduction was performed to support turbine control valve testing, condenser water box tubesheet cleaning, and Amertap system repairs. Documents and procedures reviewed are listed below.

- Operating Procedure 2C1.4, "Unit 2 Power Operation," Revision 15,
- WO 9808933, "ISOL FOR AMERTAP SCREEN CLEANING," and
- SP 2054 "Turbine Stop, Governor and Intercept Valve Test," Revision 20.

b. Observations and Findings

The inspectors attended the pre-evolution briefing for the Unit 2 power reduction on September 19, 1998. During the briefing, the licensee staff discussed the load reduction rate, scheduled maintenance activities and relative timing, equipment to be removed from service, core reactivity effects, previous neutron axial flux distribution (ΔI) problems experienced during power transients late in core life, communications, personnel assignments, expected alarms, and control of operator trainees. The briefing was attended by Unit 2 control room operators and other non-licensed operators, chemistry personnel, and the shift manager. The inspectors concluded that the pre-evolution briefing was comprehensive and effective.

The power reduction was performed in a slow and controlled manner. Both the shift manager and Unit 2 shift supervisor maintained adequate overview of the unit during the power reduction. The reactor operator (RO) and the lead reactor operator (LRO) supervised operator trainees who performed most of the plant manipulations during the power reduction. Control of the trainees was excellent. Licensed operators closely supervised trainee actions and continuously asked questions concerning plant status and ongoing trends.

This power reduction occurred late in core life with Unit 2 approximately 17 months into an 18-month operating cycle. Prior to reducing power, the nuclear engineering department had issued guidance to the Unit 2 operators which addressed the reactivity effects of power defect, xenon buildup and decay, and control rod movement. The operators discussed factors associated with control of neutron flux profiles late in core life and developed a course of action to maintain ΔI within prescribed limits before the power reduction began. The course of action included the timing and amount of boration and dilution required, expected amounts of rod insertion required as power decreased, the need to maintain rod position above the mid-plane of the core, maintaining Tave (the average reactor coolant temperature) and Tref (the reference reactor coolant temperature) within limits, and the desired position in the ΔI target band as power was decreased. The inspectors reviewed the actions discussed by the operators and noted no concerns. During the power reduction, the operators implemented the previously discussed plan and followed procedural requirements.

Despite the actions of the operators, ΔI went out of band high at +4%, at 5:41 a.m., on September 20, 1998, and did not return to the target band until 6:37 p.m. Technical Specification (TS) 3.10.B.7.b, required that reactor power be maintained less than 50 percent for 23 of 24 hours after ΔI had returned to the target band. Operators delayed power ascension until 6:37 p.m., on September 21, 1998, to ensure that the TS requirement was met. No TSs or safety limits were violated while ΔI was out of the target band. The licensee initiated an Error Reduction Task Force (ERTF) investigation of the event. The ERTF report is expected to be issued by December 31, 1998.

The inspectors discussed the ΔI event with the superintendent of nuclear engineering and the corporate nuclear analysis division (NAD) project manager. They stated that actual neutron flux profiles late-in-core-life were difficult to predict and dependent on precisely when control rods were moved and how power was reduced. While ΔI was out-of-band, the licensee recorded core data on the emergency response computer system. The NAD project manager added that this information would be used to improve the existing neutron flux model in the coming months.

The power ascension commenced on the evening of September 21. The evolution was performed in a slow and controlled manner. Personnel from the nuclear engineering department were present to collect data for the ΔI analysis and to provide technical expertise to the control room operators should the problem with ΔI control reoccur. Two RO trainees were stationed in the control room under the direct supervision of the RO and the LRO. Throughout the evolution, the inspectors noted good reactivity management, three-way communications, and good management oversight. The inspectors had no concerns with the conduct of the power ascension or observed any difficulties in controlling ΔI within the required band.

c. Conclusions

Operators reduced Unit 2 power to 40 percent to support turbine valve testing and subsequently returned it to 100 percent in a controlled and deliberate manner. Expected deviations of neutron flux distributions from the target band were handled well by operators.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Violation 50-282/98006-01(DRS); 50-306/98006-01(DRS): Failure To Follow a Procedure for Isolating a Breaker. This violation was previously discussed in Inspection Report 50-282/98006(DRS); 50-306/98006(DRS), Section O1.6, and in the Northern States Power (NSP) response dated June 25, 1998, to the Notice of Violation. Licensee corrective actions for this violation were being followed by commitment tracking number 19981343. The inspectors verified that administrative work instruction (AWI) 5AWI 3.10.0, "Control and Operation of Plant Equipment," Revision 8, Step 6.9.4.c.2.b, contained instructions for verifying that a molded case circuit breaker was de-energized when the breaker already contained an isolation card placing it in an "OFF" position.

The inspectors also verified that the licensee had reviewed 5AWI 3.10.0 to identify any additional problems. The review identified two procedure steps that needed revision. The first was Step 6.9.1.b, which described placing locks on locally controlled equipment in shop areas. Step 6.9.1.b, required control of the locks to be governed by departmental section work instructions; however, no existing section work instructions covered this situation. The second step that required revision was Step 6.9.4.b.4.a, which discussed attaching safety tags to 4160-volt breaker cubicle tray flanges. However, certain 4160-volt breakers in the cooling tower pump houses did not have cubicle tray flanges on which to attach a safety tag. The licensee supervisor in charge of commitment tracking number 19981343 stated that 5AWI 3.10.0 was being revised to address those two steps and that this action was expected to be completed by October, 31, 1998.

Because all the corrective actions associated with the violation were reasonable, adequate, and had either been completed or had been entered into the licensee's corrective action tracking system, this violation is closed.

O8.2 (Closed) Violation 50-282/98006-03(DRS); 50-306/98006-03(DRS): Inadequate Procedure for Transferring Power Supply for Motor Control Center 1MA2. This violation was previously discussed in Inspection Report 50-282/98006(DRS); 50-306/98006(DRS), Section O3.1, and in the NSP response dated June 25, 1998, to the Notice of Violation. The inspectors verified that a new temporary change process had been developed and implemented on August 3, 1998. The inspectors reviewed the new temporary change process administrative work instruction 5AWI 1.5.10, "Procedure Temporary Changes," Revision 1, and noted that Steps 6.2.g, 6.4.d, and 6.4.f, contained specific instructions concerning expiration dates for temporary procedure changes.

Other corrective actions associated with this violation are listed below.

- All project engineers review the relationship of this violation to PINGP [Prairie Island Nuclear Generating Plant] form 1218, "Turnover Checklist."

  The inspectors verified that this corrective action item had been entered into the licensee's commitment tracking number system (Number 19981323) and that adequate progress had been made toward completion of the item. The deadline for completing this commitment was set by the licensee for December 31, 1998. The commitment included changing 5AWI 6.1.7, "Design Change Work Orders," Revision 0, and 5AWI 6.1.9, "Design Change Turnover For Operation," Revision

0, to better describe the completion of PINGP form 1218 prior to releasing a system for preoperational testing.

- Determine whether active temporary memos should be reviewed for continued applicability on a periodic basis.

  The inspectors verified that this corrective action item had been entered into the licensee's commitment tracking number system (Number 19981344) and that adequate progress had been made toward completion of the item. The licensee had decided that a periodic review of active temporary memos was needed and expected to implement a review process by December 31, 1998.

Since all the corrective actions associated with violation 50-282/98006-03(DRS); 50-306/98006-03(DRS) were reasonable, adequate, and have either been completed or were being adequately followed by a licensee tracking system, this violation is being closed.

O8.3 <u>(Closed) Licensee Event Report (LER) 50-306/97018 (2-97-004)</u>: Plant Shutdown Due to Greater than Allowable Leakage from Maintenance Airlock per Technical Specifications. This LER was previously discussed in Inspection Report 50-282/97018(DRP); 50-306/97018(DRP), Section O1.1, and in LER 2-97-004, dated October 27, 1997. This event involved the results of a Unit 2 maintenance airlock volumetric test that exceeded limit in TS 4.4 for airlock leakage. The repairs were not completed until the reactor was shutdown. The leakage occurred through the operating mechanism shaft seals.

The inspectors verified that the test procedures for the maintenance and personnel airlocks had been revised to require a complete inspection of the entire airlock pressure boundary before leakage was assigned to one door. The inspectors also discussed the LER with work planning personnel and verified that WO 9810750, "Verify Maintenance Airlock Alignment and Inspect Shaft Assembly," had been written to investigate operating mechanism shaft seal misalignment and, if possible, correct it during the upcoming Unit 2 refueling outage.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (IPs 61726, 62707)

The inspectors observed all or portions of the maintenance and surveillance test activities in accordance with the listed procedures. Included in the inspection was a review of the SPs, preventive maintenance procedures (PMs), or WOs listed, as well as the appropriate USAR sections regarding the activities. The inspectors focused their observations on risk-significant surveillance, testing, and maintenance activities. The inspectors verified that the surveillance procedures observed met the requirements of the TSs.

- SP 1087, “SI [Safety Injection] Pump Monthly Lubrication,” Revision 4;
- SP 1106A, “12 Diesel Cooling Water Pump Test,” Revision 53;
- SP 1106B, “22 Diesel Cooling Water Pump Test,” Revision 52;
- SP 1135B, “Reactor Protection Logic Test At Power - Train B,” Revision 24;
- SP 1322, “Unit 1 4.16KV Safeguards Bus Inspection,” Revision 8;
- SP 2089, “Residual Heat Removal Pumps and Suction Valves From the Refueling Water Storage Tanks,” Revision 53;
- SP 2305, “D6 Diesel Generator Slow Start Test,” Revision 9;
- SP 2316, “480V Safeguards Bus Inspection,” Revision 8;
- SP 2322, “Unit 2 - 4.16KV Safeguards Bus Inspection,” Revision 12;
- PM 3002-2-22, “22 Diesel Cooling Water Pump Annual Inspection,” Revision 17;
- WO 9810524, “Measure Silencer DP [Differential Pressure] During Operation”;
- WO 9810689, “AFWP [Auxiliary Feedwater Pumps] Discharge Pressure Indicators - Unit 1”;
- WO 9810703, “AFWP Discharge Pressure Indicators - Unit 2”;
- WO 9811010, “Move SFP [Spent Fuel Pool] Covers To Prepare For Fuel Receipt”;
- WO 9811258, “Remove 2 SFP Covers From SFP Enclosure”;

- SP 2305, “D6 Diesel Generator Slow Start Test,” Revision 9;

- WO 9811447, “22 TDAFWP OBRG MTL TE [22 Turbine-Driven Auxiliary Feedwater Pump Outboard Metal Temperature Element]”; and

- WO 9811049, “Repair CV-31754 [11 Residual Heat Removal Pump Unit Cooler Chilled Water Supply Control Valve] (Not Stroking Properly).”

b. Observations and Findings

- The inspectors attended the pre-job briefing and witnessed testing of the 11 and 12 SI pumps in accordance with SP 1087. The pre-job briefing was adequate and discussed communications, steps not required to be performed in the surveillance procedure, and independent verifications needed. The inspectors noted that all personnel involved in testing the pumps, both locally and in the control room, were present for the pre-job briefing. During the running of the pumps, the local operators in the auxiliary building did a good job monitoring pump status. The operators frequently checked casing, lube oil, bearing, packing gland, motor, and recirculation line temperatures as well as lube oil and recirculation line flow rates. The pumps operated normally and the surveillance procedure was completed satisfactorily.

- The inspectors attended the pre-job briefing and witnessed the testing of the safety-related 12 diesel-driven cooling water pump (DDCLP) in accordance with SP 1106A. The inspectors noted that all personnel involved with the surveillance procedure attended the briefing. The briefing itself was adequate and discussed communications, the general procedure outline, amperage and vibration readings, contingency actions, and procedural required alignment of the safety-related cooling water header.

  When the test was completed, the American Society of Mechanical Engineers (ASME) Section XI, performance curve plot of flow versus pressure for 12 DDCLP fell into the alert range. Operations Manual Section H10.1, “ASME Section XI Inservice Testing Implementation Program,” paragraph 7.3.3, stated that “[P]umps falling in the alert range shall be evaluated for operability within 96 hours and frequency of testing shall be doubled until the cause is determined and rectified.” The evaluation of the operability of 12 DDCLP was subsequently documented in non-conformance report (NCR) 19982264 within the required 96 hours. The evaluation determined that based on a review of 12 DDCLP historical data, the hydraulic testing results were acceptable and 12 DDCLP was operable. An increase in pressure by less than one half pound per square inch, at the tested flow rate, or an increase of less than 100 gallons per minute, at the tested pressure, would have put 12 DDCLP in the acceptable range. Nominal values of pressure and flow had been approximately 97 pounds per square inch and 8800 gallons per minute, respectively. The ASME Section XI frequency requirement for 12 DDCLP testing was quarterly. As was previous practice, the licensee continued to test 12 DDCLP monthly, thereby satisfying the ASME Section XI doubling frequency requirement. The inspectors verified that when

SP 1106A was performed a second time during the inspection period, flow and pressure values fell within the acceptable range of the 12 DDCLP pump curve.

- The inspectors observed operability testing of 22 DDCLP in accordance with PM 3002-2-22, “22 Diesel Cooling Water Pump Annual Inspection,” Revision 17, Step 7.6. The inspectors witnessed satisfactory testing of the pump low speed stop, overspeed trip, and high speed stop. Control of the pump was verified from both the local and control room panels. The pump was subsequently returned to service after performance of the normal monthly surveillance, SP 1106B.

- The inspectors attended the pre-job briefing and witnessed testing of the 21 residual heat removal (RHR) pump in accordance with SP 2089, Step 7.3. The pre-job briefing was adequate, included all personnel involved in the surveillance, and discussed communications, expected indications and personnel responsibilities and actions. The inspectors observed local operation of the RHR pump and associated essential support equipment. No deficiencies were noted. The inspectors observed operators using good radiological practices when taking a chemistry sample from the RHR pump discharge in accordance with SP 2089.

- The inspectors attended the pre-job briefing and witnessed testing of the D6 emergency diesel generator (EDG) in accordance with SP 2305 and WO 9810524. The pre-job briefing was adequate and covered prerequisites, the installation and removal of a special manometer to measure exhaust silencer differential pressure, communications, contingency actions, and the assignment of operator responsibilities. The objective of WO 9810524 was to measure the differential pressure across the D6 exhaust silencer. If the differential pressure was less than 13.8 inches of water, the vendor recommended that the silencer not be inspected during an upcoming refueling outage. Instrumentation and control (I&C) personnel exhibited a good questioning attitude while taking differential pressure measurements when they realized that the local diesel room ventilation system might affect the manometer’s atmospheric pressure reading. The I&C personnel coordinated with security personnel and opened a local diesel room door to the outside protected area. One end of the manometer connection was run outside the diesel room so that an accurate measure of atmospheric pressure would be obtained.

  The inspectors noted that with the EDG carrying 100 percent load, an exhaust gas temperature high alarm occurred. The inspectors observed that the operators consulted the remote alarm response procedure C60003, Revision 5, Annunciator Location 60003-0604, and performed the required actions. The inspectors discussed the exhaust gas temperature alarm with the observing system engineer. One of the conditions that could cause a high gas temperature alarm occurred when an individual cylinder exhaust gas temperature deviated from the average of all the cylinder exhaust temperatures by more than 180 degrees Fahrenheit. The system engineer stated that an average exhaust gas temperature electronic module in the local auxiliary operating panel was out-of-calibration and was causing the exhaust gas temperature high alarm to come in early, giving a conservative indication of a problem. The inspectors checked individual cylinder exhaust temperatures and the average system exhaust temperature to verify the system engineer's statement. This check revealed that the alarm was occurring early and that the largest deviation between an individual cylinder exhaust gas temperature and the average of all the other cylinder temperatures was 140 degrees Fahrenheit. The surveillance procedure was subsequently completed with no other difficulties. The licensee was pursuing with the vendor the problem with module.

- The inspectors reviewed WOs 9811010 and 9811258 and the heavy loads maintenance procedure D58.5.2, "Spent Fuel Pool Covers Movement," Revision 0, for handling requirements for the spent fuel pool covers over irradiated fuel. The inspectors verified that maintenance procedure D58.5.2 contained precautions related to the height and overlap of the spent fuel pool (SFP) covers with the concrete spent fuel pool walls. These precautions were required by conditions added by license amendment Nos. 130/122. The inspectors observed the removal of two SFP covers from the SFP enclosure. The evolution was performed in a controlled and cautious manner. The inspectors noted that a nuclear engineer who was present during the lifting of the SFP covers ensured that the limitations imposed by D58.5.2 were met.

- The inspectors reviewed the plant configuration and maintenance activities associated with WO 9811049 from a risk perspective. Work order 9811049 contained instructions for the repair of the unit cooler chilled water supply control valve for the 11 RHR pump. Since the unit cooler was considered essential support equipment for the RHR pump, work on the unit cooler caused the RHR pump to be considered inoperable.

  The inspectors questioned the probabilistic risk assessment (PRA) team leader about the risk effects associated with the 11 RHR pump being declared inoperable. The team leader stated that the risk achievement worth (RAW) associated with 11 RHR pump was 1.28, meaning that if the 11 RHR pump were unavailable for an entire year, the Unit 1 core damage frequency (CDF) would increase by 28 percent from a nominal value of 5×10^{-5} per year to approximately 6.4×10^{-5} per year. The system engineer also stated that, excluding common cause failures, the Fussell-Vesely (FV) value associated with the 11 RHR pump was approximately 6.4×10^{-4}. Fussell-Vesely measures the overall contribution of an event to CDF and ranges between 0 and 1. Systems with a higher value of FV contribute a larger percentage of the total risk measure. Taken together, the RAW and FV values for the 11 RHR pump being declared inoperable had minimal impact on the Unit 1 CDF.

  Actual work on the unit cooler made the 11 RHR pump inoperable for 25 hours. The approximate risk effect associated with the 11 RHR pump having been declared inoperable was equal to the CDF multiplied by time. Thus, the nominal increase in Unit 1 risk was approximately equal to 25 hours x 1 day/24 hours x 1 year/365 days x 6.4×10^{-5} per year or 1.8×10^{-7}. This increase in risk was small.

- The inspectors observed the calibration of four auxiliary feedwater pump discharge pressure gauges (PI [Pressure Indication] 11334, 11335, 11336, 11337) in accordance with WOs 9810689 and 9810703. All indications were calibrated to within acceptable tolerances with only PI 11334 needing minor adjustments from the as-found condition. The inspectors verified that the standard used to calibrate the gauges was itself in calibration.

During performance of WOs 9810689 and 9810703, the inspectors observed that the pump outboard bearing packing gland leakoff line for the safety-related 22 TDAFWP was leaking onto a flexible conduit leading to the resistance temperature detector (RTD) element. The packing gland was leaking approximately two drops per second onto the conduit. The inspectors were concerned that over time, the packing gland leakoff would corrode the flexible conduit causing failure of the RTD element and loss of one of the 22 TDAFWP outboard bearing temperature indications. The inspectors brought the concern to the attention of the Unit 2 shift supervisor and an I&C supervisor. The shift supervisor and I&C supervisor acknowledged the concern and wrote WO 9811447 to reposition the RTD flexible conduit during the upcoming Unit 2 refueling outage.

c. Conclusions

All the routine maintenance activities and surveillance tests observed by the inspectors were conducted well, utilized safe work practices, and demonstrated good communication and coordination between the control room and workers performing the work. Proper actions were taken when the inspectors identified that packing gland leakage could have caused the partial loss of safety-related, turbine-driven auxiliary feedwater pump bearing temperature monitoring capabilities.

M1.2 D5 Emergency Diesel Generator 18-Month Planned Maintenance

a. Inspection Scope (IP 62707)

The inspectors reviewed the D5 EDG planned maintenance activities. This review included procedures and electrical and mechanical isolation records, and observations of actual maintenance. The inspectors also reviewed the effects of crankcase overpressure and the subsequent abnormal operating procedure actions. Documents reviewed as part of this inspection are listed below.

- PM 3001-2-D5, “D5 Diesel Generator 18 Month Inspection - Mechanical,” Revision 1;
- I&C Preventative Maintenance Procedure ICPM 2-500A, “D5 Miscellaneous Instruments Calibration (D5 Outage) 18 Month Frequency,” Revision 1;
- ICPM 2-500C “D5 Electrical Panels Instrument Calibration,” Revision 0;
- SACM [Societe Alsacienne De Constructions Mecaniques De Mulhouse] Diesel Engines Instruction Manual XH-2610-1364;
- Remote Alarm Response Procedures C50001-0607, C50003-0608,

C60001-0607, C60003-0608, “Crankcase Pressure High Trip,” Revision 0, and

- Operating Procedure 2C20.7, “D5/D6 Diesel Generators,” Revision 10.

b. Observations and Findings

Technical Specification 4.6.A.3.a, required that the licensee thoroughly inspect each EDG using procedures based on the manufacturer’s recommendations. This requirement was met by performing procedures PM 3001-2-D5, ICPM 2-500A, and ICPM 2-500C. The inspectors reviewed the TS limiting condition for operation (LCO) requirements, procedural documentation, and work practices throughout the D5 EDG outage. The inspectors also attended several pre-evolution briefings and maintenance updates.

The inspectors reviewed 5AWI 3.10.0, “Control and Operation of Plant Equipment,” Revision 8, and equipment isolation list 98-04480, Version 1, associated with PM 3001-2-D5. The equipment isolation hold-and-secure cards reviewed were clearly labeled and the components were in the position indicated on the cards. The work order, preventative maintenance procedure, applicable drawings, and the diesel instruction manual were present at the job site and were routinely used. The system engineer was frequently present at the work site and provided information to workers as required. Foreign material exclusion controls were also in-place.

The inspectors witnessed removal and testing of several diesel engine fuel oil injectors in accordance with PM 3001-2-D5, Steps 8.3.2.A, B, and C. All injectors lifted at the required pressure, exhibited the proper spray pattern, and did not leak when maintained just below opening pressure for 10 seconds. The injector test stand and test gauge met the manufacturer’s specifications.

The inspectors reviewed the quality control department (QC) overview of the D5 maintenance activities. The QC audit plan for the work was also discussed with a QC supervisor. The plan contained several mandatory hold-and-release points associated with witnessing and reviewing critical maintenance activities. Hold points included injector testing, valve lash adjustments, boroscopic inspections of cylinder internals, and checking of crankshaft clearances. The inspectors observed QC inspectors satisfactorily evaluating and releasing a hold point in the PM associated with fuel oil injector testing.

The inspectors reviewed data from D5 and D6 EDG crankcase overpressure events and the subsequent corrective actions specified in remote alarm response procedures. In all cases, a high crankcase pressure with the EDG operating automatically tripped and locked out the respective EDG, if no emergency start signal was present. Initial operator remote alarm response procedure actions included verifying the high crankcase pressure and, if feasible, stopping the diesel generator. Subsequent actions told the operator to, “Initiate repairs, as necessary.” Operating procedure 2C20.7, precaution 3.2, however, stated in part that, “High crankcase pressure indicates the possible existence of an explosive gas mixture... Before preforming maintenance on a diesel that has been shutdown because of high crankcase pressure, ensure the diesel has cooled thoroughly.” The inspectors were concerned that early access to the crankcase before the engine had cooled could result in a secondary explosion creating a personnel hazard to the operators. The remote alarm response procedures, however, contained no precautionary statements to warn operators of the explosion potential. The inspectors noted that placards were installed on the side of the D5 and D6 diesel engines which advised waiting ten minutes after the engine was shut down before removing any inspection cover.

The inspectors reviewed sections of the EDG technical manual and questioned the vendor representative concerning the need to allow the diesel engine to cool following a high crankcase pressure diesel generator trip and lockout. The representative stated that the mass of the engine was not great enough and would, therefore, not generate enough heat to cause a secondary explosion if access was gained to the crankcase before the engine had cooled. No statements concerning delayed crankcase access following a high pressure trip were identified by the inspectors in EDG technical manual Section 3-5-1-7 describing the crankcase overpressure relief device and alarm functions.

The inspectors discussed the inconsistency between the 2C20.7 operating procedure precaution statement and the D5/D6 remote alarm response procedure with the system engineer. The system engineer stated that the inspectors' observation would be considered during the next biannual procedure review and that, in practice, engine access would be delayed following a high crankcase pressure trip while the appropriate personnel were contacted and work orders written.

c. Conclusions

The D5 EDG 18-month preventative maintenance was performed in a satisfactory manner. The quality control department established adequate hold points at appropriate steps during the maintenance activities. Foreign material controls were evident and properly applied. The inspectors noted a minor inconsistency between the D5 operating procedures and the remote alarm response procedure concerning crankcase overpressure situations.

M1.3 11 Shield Building Ventilation Filter System Rendered Inoperable Without Entering the Applicable TS LCO Statement

a. Inspection Scope (IPs 61726, 62707)

The inspectors reviewed the circumstances surrounding the opening of an 11 shield building special ventilation system (SBSV) filter door without entering the applicable TS LCO statement. Documents examined as part of the review of this event are listed below.

- SP 1080.1, "11 Shield Building Ventilation Filter Removal Efficiency Test," Revision 8;

- SP 1055.1, "121 Control Room Special Ventilation System Filter Removal Efficiency Test," Revision 7;

- Radiation Protection Form RP-111a, “Radiation Protection Survey Record,” dated Tuesday, September 15, 1998, at 0805;

- WO 9806421, “SP 1055.1 121 Control Room Special Vent System Filter Removal and Efficiency Test”; and

- WO 9806425, “SP 1080.1 11 Shield Building Vent Filter Removal and Efficiency Test.”

b. Observations and Findings

After reviewing a contamination survey map made in support of work to be performed in accordance with SP 1080.1, a licensee radiation protection supervisor suspected that a radiation protection specialist (RPS) had opened a filter door on 11 SBSV without control room personnel having entered the applicable TS LCO statement. The supervisor contacted the Unit 1 shift supervisor who verified that the applicable LCO statements had not been officially entered until two hours later, after the contamination survey had been logged as completed.

Surveillance procedure SP 1080.1, Step 7.4, required entry into TS LCO statements 3.6.E and 3.6.G. Once these LCOs had been entered, the RPS was then supposed to perform a contamination survey of the inside of 11 SBSV filter housing in accordance with Step 7.7. When the RPS opened the housing door, prior to being directed to as required by SP 1080.1, a four square-foot opening was created in the SBSV and auxiliary building special ventilation system (ABSV) zones. This opening rendered both the ABSV and SBSV inoperable without the required entry into TS LCO statements 3.6.E and 3.6.G.

On the morning the RPS completed the contamination survey, maintenance workers were performing two ventilation system work items. The first was SP 1055.1 on the 121 control room special ventilation system (WO 9804621) and the second was SP 1080.1 on 11 SBSV (WO 9806425). The work orders were intended to be performed in series beginning with the control room ventilation work. While at the access control point for the auxiliary building, the maintenance workers told the RPS that two work orders would be performed that day, one on the control room ventilation system and one on 11 SBSV. The RPS saw the cover sheet for the two WOs but did not review the specific steps requiring the contamination survey. When the RPS later surveyed the control room ventilation system, the specialist mistakenly assumed that it was appropriate to survey the 11 SBSV at the same time. The RPS did not review and was unaware of the procedure requirements in SP 1080.1, Steps 7.4 and 7.7, which directed the survey to be performed after the applicable LCOs had been entered.

The inspectors interviewed personnel involved in the event and learned that the pre-job briefing for SP 1080.1 did not include all personnel involved with the work. The cognizant maintenance supervisor discussed SP 1080.1 with the two maintenance workers assigned to the WOs. The Unit 1 RO, LRO, and shift supervisor discussed SP 1080.1 amongst themselves; however, the system engineer did not discuss the work with personnel from any other departments and no inter-departmental pre-job briefing was held between operations, engineering, maintenance, and health physics personnel.

On the same afternoon, the plant manager halted all work associated with ventilation filter systems on Units 1 and 2 while the circumstances of the missed LCO entries were investigated. Later on September 28, 1998, station management stopped most work for two hours to discuss the recent SBSV events with personnel. All station departments were involved. Discussions were led by department superintendents and included procedure use and adherence, pre-job briefings, accountability, management expectations, and self-checking techniques. The plant manager also issued an electronic mail message to all site supervisors and wrote an article for the site newsletter which discussed dealing with distractions, procedural adherence expectations, pre-job briefings, and communications. On September 29, 1998, the hold on ventilation system work was lifted. Additional controls on subsequent ventilation system work included requiring quality control department oversight for the next two ventilation filter system work tasks, revising the applicable surveillance procedures to require inter-departmental pre-job briefings, providing more detail on RPS actions, and the completion of the investigation.

Technical Specification 6.5 required that detailed written procedures be prepared and followed for maintenance and test procedures associated with engineered safeguards and equipment as required in the facility license and TSs. Both the ABSV and SBSV are described as required equipment in TSs 3.6.E and 3.6.H. Failure to follow SP 1080.1, "11 Shield Building Ventilation Filter Removal Efficiency Test," Revision 8, Steps 7.4 and 7.7, in the order specified, is a violation of TS 6.5 because written procedures applying to equipment described in the facility TSs were not followed. This resulted in an inadvertent entry into TS LCO statements 3.6.E and 3.6.H without the knowledge of control room operators. The corrective actions for this problem, as discussed in the preceding paragraph, were adequate. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 50-282/98018-01(DRP)).

The safety significance associated with the RPS opening the 11 SBSV filter door without entering the appropriate LCOs was low. The door remained open for less than one minute and could have been closed if the 11 SBSV or ABSV started. When the RPS finished the contamination survey the door was returned to its normal locked and closed position.

c. Conclusion

Problems were evident with inter-departmental work control and procedural adherence controls when a radiation protection specialist performed a shield building ventilation system contamination survey without the control room having entered the applicable TS LCO statements. This was the second problem associated with safety-related SBSV work in a 14-day period. The first SBSV problem was NRC-identified and resulted in a cited violation (Inspection Report 50-282/98015(DRP); 50-306/98015(DRP), Section M1.3, Violation 50-282/98015-01(DRP)). Although the licensee's corrective actions were adequate and reasonable, the proximity of the two SBSV occurrences highlights the need for continued improvement in the work control and procedural adherence areas.

M8 Miscellaneous Operations Issues

M8.1 (Closed) Violation 50-306/98003-02(DRP): Inappropriate Work Order Procedure for Substation Work Resulted in an Engineered Safety Feature System Actuation. This violation was previously discussed in Inspection Report 50-282/98003(DRP); 50-306/98003(DRP), Section M3.1, and in the NSP response dated April 8, 1998, to the Notice of Violation. The short-term corrective action for this violation included issuing a memorandum to electrical system engineering personnel discussing management expectations for technical review of work orders. The inspectors verified that this action had been completed on April 29, 1998. The long-term corrective action for this violation included a review of administrative work instructions to ensure that work control responsibilities were clearly defined. The inspectors verified that this review was in progress and that completion of the review was being tracked (tracking number 19980698) by the licensee's corrective action program. The review of administrative work instructions was expected to be complete by January 1, 1999.

Since the corrective actions associated with violation 50-306/98003-02(DRP) are reasonable, adequate, and have either been completed or are being adequately followed by a licensee tracking system, this violation is closed.

III. Engineering

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. No discrepancies were noted.

E2.2 Use of PRA for Work Planning and Plant Configuration Control

a. Inspection Scope (IPs 37551, 92903)

The inspectors reviewed six weekly planning meeting reports, attended several work planning meetings, interviewed a PRA team leader, and reviewed the licensee's Individual Plant Examination (IPE) and Individual Plant Examination of External Events to assess the extent to which applicable PRA studies were used in daily work planning and configuration control decisions. Documents reviewed as part of this inspection are listed below.

- Prairie Island Nuclear Generating Plant Individual Plant Examination, NSPLMI-94001, Revision 0;

- Prairie Island Nuclear Generating Plant Individual Plant Examination of External Events, NSPLMI-96001, Revision 0;

- Prairie Island Nuclear Generating Plant Individual Plant Examination of External Events, NSPLMI-96001, Revision 1;

- Weekly Planning Meeting Results for September 12 - October 15, 1998;

- 5AWI 3.1.0, “Site Organization and General Responsibilities,” Revision 3, and

- Administrative Control Document Memorandum (ACDM) 1998-0018, “5AWI 3.10.0, Revision 8 - Control and Operation of Plant Equipment.”

b. Observations and Findings

The inspectors noted that 5AWI 3.1.0, Table 1, Item 3.2, defined the responsibilities of the PRA team leader as providing PRA services for items such as design changes, temporary modifications, safety evaluations, prioritization of projects, specific maintenance and operational activities, and responses to industry and NRC publications and questions. The inspectors observed that either the PRA team leader or engineer was present at all work planning meetings, as discussed in ACDM 1998-0018. At the work planning meetings, the inspectors observed that traditional TS-based work planning methods governed the work and configuration control process. The inspectors noted, however, that the PRA staff routinely provided input to department representatives at the meetings. This routine input ensured that weekly work activities were organized and scheduled so as to minimize the risk impact on Units 1 and 2. Specific examples observed by the inspectors are listed below.

- Based on PRA team leader input to the duty shift manager on October 1, 1998, performance of SP 1355, “Auxiliary Feed Pump Check Valves,” Revision 8, was delayed until annual preventative maintenance on the 22 DDCLP was completed. Having had both Unit 1 auxiliary feed water pumps sequentially removed from service during SP 1355 while 22 DDCLP was out-of-service would have increased the CDF by a factor of 8 from a nominal value of 2.07×10^{-5} to 1.68×10^{-4}.

- At a weekly work planning meeting on October 14, 1998, the PRA team leader mentioned the possible risk impact of performing work on the 12 DDCLP jacket water cooling outlet valve diaphragm (WO 9811448) and the preventative maintenance on the 12 charging pump concurrently. The 12 DDCLP is a safety-related source of cooling water which provides cooling for the component cooling water system. Reactor coolant pumps (RCP), in turn, depend on the component cooling water system to provide cooling to the thermal barrier heat exchanger and the charging pumps for normal seal flow. Removing both the 12 DDCLP and a charging pump from service at the same time could have had an increased risk impact on RCP seal failure leading to a greater chance for a small break loss of coolant accident. Because of the PRA team leader’s comments, the diaphragm repair and charging pump preventative maintenance were performed at different times.

- All weekly work planning meeting reports reviewed by the inspectors included an analysis of the impact of scheduled work on Units 1 and 2 core damage frequency. The analysis discussed and presented in graphical form each scheduled surveillance or preventative maintenance procedure that caused the plant to enter an LCO or that increased the risk level of the plant.

The inspectors reviewed the modeling tools used in PRA analysis with the PRA team leader. The team leader stated that PRA analysis was done using an Equipment Out-of-Service (EOS) Monitor model. The EOS model was based on Unit 1 plant equipment and configuration only. The assumption was made that Unit 2 equipment mirrored Unit 1 equipment. As discussed with the team leader, limitations of the current EOS model and PRA analysis are listed below.

- The EOS model required artificial inputs to ensure that the PRA analysis actually bounded the planned plant configuration when Unit 1 and Unit 2 shared equipment such as EDGs, instrument air compressors, and cooling water sources were removed from service. An example was when D5, a Unit 2 “A” train EDG, was removed from service for an 18-month preventative maintenance overhaul during the week of September 19, 1998. In order to bound the Unit 2 risk analysis for D5 being out-of-service, the EOS model required that the Unit 1 “A” train backup source of emergency power, D1, be considered out-of-service also when in reality it was available.

- The EOS monitor was based on a cutset model. A cutset is a group of failures that is collectively necessary and sufficient to cause a given event to occur. The EOS model truncated cutsets below a CDF of 10^{-9} and assumed that no equipment was currently out-of-service. Since equipment was removed from service on a continuous basis, the EOS model was limited in that it did not provide for a real-time reflection of plant conditions each time a model analysis was performed.

- Shutdown plant conditions were only partially factored into the EOS model. Instead, the licensee used the guidance in NUMARC 91-06 to control shutdown plant configuration and risk.

- The current IPE cited some large early release results but stopped short of a complete Level 2 PRA analysis. The PRA team leader stated that a complete Level 2 analysis has been completed and will be incorporated in Revision 1 to the current IPE.

To address some of these limitations, the licensee has retained a contractor to develop a separate and complete Unit 2 model using the existing Unit 1 EOS model. A Unit 2 specific model would eliminate the current need to make bounding assumptions for Unit 1 and Unit 2 shared equipment risk analysis. The contractor will also adjust the EOS monitor to reconfigure the PRA model each time an analysis was made. This adjustment would allow the EOS model to reflect exact plant conditions without the need to truncate any cutsets.

c. <u>Conclusion</u>

The PRA staff worked closely with work planning personnel and routinely participated in work planning and configuration control decisions. The inspectors noted two instances where PRA analysis influenced work scheduling so as to minimize the risk effects of out-of-service equipment. Adequate steps were being taken to address the current limitations of the PRA model used for Prairie Island Units 1 and 2.

E8 Miscellaneous Engineering Issues (IP 92903)

E8.1 (Closed) Licensee Event Report (LER) 50-282/98018 (1-98-11): Improper Acceptance Criteria in Surveillance Procedure. This LER discussed a licensee-identified condition that resulted in the application of incorrect acceptance criteria for ASME Section XI stroke time testing of a component cooling water heat exchanger cooling water outlet control valve, CV-31381. The error occurred in March 1996, when incorrect acceptance criteria were incorporated into a procedure during a revision. The procedural error remained in place until August 1998, when a Section XI engineering review of another procedure change proposal disclosed the error. During the period that the procedure was in error, valve stroke times were outside correct alert limits on four occasions and corrective actions were not taken. In no case did the valve stroke times exceed the maximum allowed time limits which would have rendered the valve inoperable.

Failure of the licensee to apply the correct acceptance criteria to safety-related component cooling water heat exchanger cooling water outlet control valve, CV-31381, was a violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” which requires that testing be performed in accordance with written test procedures that incorporate appropriate requirements and acceptance limits. The corrective actions planned or in progress appeared adequate and included the review and revision, as necessary, of pertinent testing procedures and the training of engineers on properly establishing acceptance criteria. 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 50-282/98018-02(DRP)).

E8.2 (Closed) Unresolved Item (URI) 50-282/98015-04(DRP); 50-306/98015-04(DRP): Reactor Vessel Head Weight Used in Heavy Loads License Documentation May Be in Error. This Unresolved Item was previously discussed in Inspection Report 50-282/98015(DRP); 50-306/98015(DRP), Section E3.1, and concerned a licensee-identified finding that questioned the weight of the reactor vessel head used in load drop calculations during refueling operations. The inspectors reviewed completed load drop calculation PI-5-014 which used an assumed reactor vessel head weight of 187,000 pounds and found no discrepancies. The calculation showed that previous 1981 load drop calculations bounded the PI-5-014 postulated scenarios and that no 10 CFR 50.9 violations had occurred.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Protection During New Fuel Handling Operations

The inspectors observed new fuel handing operations in accordance with maintenance procedure D9, “Nuclear Fuel Technical Evaluation,” Revision 28, and evaluated implementation of the associated radiation monitoring and contamination survey requirements. The inspectors noted that contamination surveys of new fuel assemblies were properly taken, analyzed, and logged. Radiation monitoring requirements for new fuel assemblies exterior to the spent fuel enclosure were met by using a portable radiation area monitor with an alarm setpoint between 5 and 20 millirem/hour.

P1 Conduct of Emergency Planning Activities

P1.1 Annual Medical Emergency Drill and SFP Evacuation Drill Observations

a. Inspection Scope (IP 71750)

The inspectors observed the conduct of the annual medical emergency drill and the implementation of SP 1732, “Spent Fuel Pool Evacuation Drill,” Revision 7b.

b. Observations and Findings

- The inspectors observed the annual medical emergency drill on September 15, 1998. The scenario involved a contaminated, injured individual requiring removal from a confined space. The drill package and scenario were comprehensive and contained well-defined objectives. During the drill, medical response personnel placed proper emphasis on the victim’s medical condition while taking appropriate radiological precautions. Drill coordinators provided timely and accurate information concerning patient and radiological conditions. Also, licensee emergency response personnel provided a good briefing on the victim’s condition to ambulance crew personnel prior to the victim being transported to a local hospital.

- The inspectors also observed the performance of a SFP evacuation drill in accordance with SP 1732. The drill occurred during new fuel handling operations. Once a simulated criticality accident occurred, the SRO in charge of fuel handling operations properly ordered personnel to evacuate the SFP enclosure and close open doors. Personnel accountability was performed and the results were communicated to the control room in a timely manner. An RPS promptly reported to the SFP area and began performing radiation surveys. The RPS demonstrated a good questioning attitude by asking the drill evaluator followup questions concerning alternate general area radiation monitor readings, the visual indications surrounding the simulated accident, and contacting the SRO in charge of fuel handling to obtain firsthand information about the accident.

c. Conclusions

The annual medical emergency drill and the spent fuel pool drill were conducted effectively. The participants demonstrated their ability to perform the required actions to mitigate the consequences of each event.

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 October 22, 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, Nuclear Performance Assessment Manager
G. Lenertz, General Superintendent Plant Maintenance
R. Lindsey, Site Alliance Implementation 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 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

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/98018-01(DRP)	NCV	11 Shield Building Ventilation Filter System Rendered Inoperable Without Entering the Applicable TS LCO Statement
50-282/98018-02(DRP)	NCV	Improper Acceptance Criteria in Surveillance Procedure

Closed

50-306/97018	LER	Plant Shutdown Due to Greater Than Allowable Leakage From Maintenance Airlock Per Technical Specifications
50-306/98003-02(DRP)	VIO	Inappropriate Work Order Procedure for Substation Work Resulted in an Engineered Safety Feature System Actuation
50-282/98006-01(DRS)	VIO	
50-306/98006-01(DRS)		Failure To Follow A Procedure For Isolating A Breaker
50-282/98006-03(DRS)	VIO	
50-306/98006-03(DRS)		Inadequate Procedure for Transferring Power Supply For Motor Control Center 1MA2
50-282/98015-04(DRP)	URI	
50-306/98015-04(DRP)		Reactor Vessel Head Weight Used in Heavy Loads License Documentation May Be in Error

50-282/98018-01(DRP)	NCV	11 Shield Building Ventilation Filter System Rendered Inoperable Without Entering the Applicable TS LCO Statement
50-282/98018-02(DRP)	NCV	Improper Acceptance Criteria in Surveillance Procedure
50-282/98018 (1-98-11)	LER	Improper Acceptance Criteria in Surveillance Procedure

LIST OF ACRONYMS USED

ABSV	Auxiliary Building Special Ventilation System
ACDM	Administratively Controlled Document Memorandum
ASME	American Society of Mechanical Engineers
AWI	Administrative Work Instruction
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DDCLP	Diesel Driven Cooling Water Pump
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EOS	Equipment Out-of-Service
ERTF	Error Reduction Task Force
FV	Fussell-Vesely
I&C	Instrumentation and Control
ICPM	Instrumentation and Control Preventative Maintenance Procedure
IP	Inspection Procedure
kV	Kilovolt
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LRO	Lead Reactor Operator
NAD	Nuclear Analysis Division
NCR	Non-Conformance Report
NRC	Nuclear Regulatory Commission
NSP	Northern States Power Company
PDR	Public Document Room
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance Procedure
PRA	Probabilistic Risk Assessment
QC	Quality Control
RAW	Risk Achievement Worth
RCP	Reactor Coolant Pump
RO	Reactor Operator
RPS	Radiation Protection Specialist
RHR	Residual Heat Removal
RTD	Resistance Temperature Detector
SBSV	Shield Building Special Ventilation System
SFP	Spent Fuel Pool
SI	Safety Injection
SP	Surveillance Procedure
SRO	Senior Reactor Operator
TDAFWP	Turbine-Driven Auxiliary Feedwater Pump
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WCC	Work Control Center
VIO	Violation
WO	Work Order