December 18, 1998

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

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/98020(DRP); 50-306/98020(DRP)

Dear Mr. Wadley:

On December 3, 1998, the NRC completed an inspection at your Prairie Island Nuclear Generating Plant. The enclosed report presents the results of that inspection.

Based on the results of this inspection, the inspectors concluded that performance remained strong. A challenging and unexpected dual unit outage was effectively managed and controlled. Several infrequently performed operations and complex maintenance tasks were conducted well and in a controlled and deliberate manner. Examples of these tasks included extended operation of both units with reduced reactor coolant inventory, steam generator and pressurizer manway repairs, and emergency diesel generator five-year preventive maintenance activities. Operators also responded well to two unexpected reactor trips and conducted a reactor startup without problems.

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

Sincerely,

/s/ Bruce L. Burgess

Bruce Burgess, Chief
Reactor Projects Branch 7

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

Enclosure: Inspection Report 50-282/98020(DRP); 50-306/98020(DRP)

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

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REGION III

Docket Nos:	50-282, 50-306
License Nos:	DPR-42, DPR-60
Report No:	50-282/98020(DRP); 50-306/98020(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	October 23 through December 3, 1998
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Resident Inspector S. Thomas, Resident Inspector
Approved by:	Bruce Burgess, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Units 1 & 2
Prairie Island Inspection Report 50-282/98020(DRP); 50-306/98020(DRP)

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

Operations

- All normal plant operations, as well as Unit 2 refueling operations, were conducted well, without significant problems. (Section O1.1)

- The licensee identified two isolation tag errors associated with the Unit 2 refueling outage that, while not safety significant, were caused by inattention-to-detail on the part of the operators attaching the tags. Subsequent inspector reviews found no indications of programmatic equipment isolation problems. (Section O1.1)

- The operators took prompt, effective actions to place the Unit 1 reactor in a safe condition until the cause for the negative flux rate reactor trip had been determined. (Section O1.2)

- Unit 1 reactor coolant system (RCS) draining and refilling evolutions were conducted in a slow, controlled, and deliberate manner. Whenever RCS inventory changes were being made, extra personnel were assigned to the operating crew, communications were formal, vent and drain paths were carefully scrutinized, and operators frequently checked diverse level indications. (Section O1.3)

- Operations personnel maintained good awareness and control of Unit 2 plant equipment and trainees during a routine refueling outage shutdown. The crew responded effectively to an unexpected turbine trip/reactor trip which occurred during the shutdown at 22 percent power. Although not complete at the end of the inspection period, the licensee's investigation into the cause of the turbine trip was reasonable and methodical. Operations with reduced reactor coolant inventory preceding refueling operations were managed well. (Section O1.4)

- The Unit 1 reactor startup and power ascension were performed in a safe and conservative manner. (Section O1.5)

- Two operating crews exhibited a lack of Technical Specification awareness by not applying the applicable Limiting Condition for Operation action statement time requirements associated with intermittent flux tilt alarms, until the issue was raised by the inspectors. (Section O1.5)

- Plant management effectively controlled and prioritized activities during a challenging and unexpected dual unit outage. (Section O6.1)

- The licensee adequately investigated and evaluated NRC concerns with the effects of chemicals from melted plastic tags on stainless steel piping and valves. (Section O8.1)

Maintenance

- The 13 routine maintenance activities and surveillance tests observed by the inspectors were performed well and demonstrated good communications and coordination between the control room and personnel performing the work. An astute member of the site safety department stopped work associated with Unit 1 condenser waterbox cleaning when she noticed that the confined space entry permit did not contain complete documentation concerning safe personnel working conditions. (Section M1.1)

- Unit 2 reactor vessel head and upper internals removal was accomplished in an acceptable manner. However, two minor attention-to-detail discrepancies occurred when the reactor head was lifted. One concerned using an unmatched digital readout meter with a load cell and the other was failure of the control room to communicate to containment personnel when changing containment audible source range nuclear instrument channels. (Section M1.2)

- The licensee took adequate actions to identify the source of a Unit 1 RCS leak. Once the location of the leak was identified as the cold leg manway for the 11 steam generator, a conservative decision was made to reduce RCS inventory and make repairs. Appropriate engineering oversight and maintenance resources were utilized effectively to repair the steam generator hot and cold leg and the pressurizer manways. (Section M2.1)

- The licensee took adequate action to address the repeated control rod drive mechanism patch cable fault issue. After the second dropped rod event, the licensee took conservative actions to enlist the aid of the cable vendor to assist in the root cause evaluation of the cable fault and to procure improved control rod and rod position indication patch cabling for both units. (Section M2.2)

- The D6 emergency diesel generator five-year preventive maintenance was performed well, with no discrepancies noted by the inspectors. The initiative taken to qualify experienced maintenance personnel as level 1 quality control inspectors to provide extensive coverage during maintenance activities was particularly effective in ensuring successful completion of the maintenance. (Section M2.3)

Engineering

- Once the control room noise reduction design change received appropriate resources for implementation, the first phase of the project was successfully completed in a timely manner. The increase in number and size of the branch ducts, in conjunction with the installation of low noise air diffusers, effectively reduced the background noise in the control room during all modes of control room ventilation operation. (Section E2.1)

Plant Support

- Radiological precautions and controls associated with removing the reactor vessel head and upper internals during the Unit 2 cycle 19 refueling outage were effective in minimizing personnel dose. (Section R1.1)

Report Details

Summary of Plant Status

From October 23 to October 29, 1998, Unit 1 operated at or near 100 percent power. On October 29, Unit 1 experienced a negative rate flux trip from 100 percent power caused by a dropped control rod. Unit 1 returned to full power operation on November 19, and remained there for the duration of the inspection period. Unit 2 operated at or near full power until it was taken off-line on November 7 for a refueling outage. During the Unit 2 shutdown, a turbine trip occurred causing the reactor to trip from approximately 22 percent power.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

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

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

b. Observations and Findings

- On November 3, 1998, the inspectors noted that the upper door latch for door 159 did not work. The door provided ingress and egress to the 121 control room chiller room. The door served as both an auxiliary building special ventilation zone boundary and as a control room envelope boundary. The inspectors brought the faulty upper door latch to the attention of the control room habitability system engineer.

  The system engineer verified the latch was faulty and stated that the USAR Sections 10.3.3 and 10.3.4 required that the door remain closed as part of the design basis calculations concerning control room dose to operators and auxiliary building special ventilation system operations. The system engineer stated that the differential pressure caused by the 121 control room ventilation system starting could cause the door to open, compromising the auxiliary building special ventilation and control room envelope boundaries. The system engineer subsequently wrote Work Order (WO) 9811999 to direct repairs of the door latch and documented the inspectors' finding in Nonconformance

Report (NCR) 19982854. As reported in the NCR, the licensee concluded that no conditions of inoperability existed since a remote alarm was provided for the control room if the door remained open for more than 30 seconds. An operator would then be dispatched to close the door if it opened during a start of the control room ventilation system.

- On November 12, 1998, the licensee identified two Unit 2 equipment isolation tag (hold or hold and secure card) errors. The first error was the interchange of hold cards for the disconnect switches of the 2MX and 2MY transformers. The second error was the interchange of the hold cards for the A phase ground connection for the Unit 2 main generator 345-kiloVolt (kV) transformer with the cards for the C phase connection. Both tagging errors occurred despite clear switchgear labeling on the components being isolated.

  Because of the two licensee-identified tagging errors, the inspectors reviewed 51 hold and secure cards related to the following safety-related, Unit 2, refueling outage WOs:

  - WO 9810427, "D6 Five Year Maintenance PM [Preventive Maintenance], Controlling Work Order";
  - WO 9807489, "Bus 26 Inspection";
  - WO 9804517, "P3124-1-22 22 RHR [Residual Heat Removal] Pump Annual Inspection"; and
  - WO 9810388, "P3119-2-22, 22 Component Cooling Heat Exchanger."

  All hold and secure cards were found to be attached to the proper component, the components were placed in the proper isolated position or state, and the correct independent verifications were performed as required. In reviewing WO 9810427, the inspectors noted minor discrepancies between wording on 6 of 16 hold and secure cards and wording on equipment labels.

- The inspectors observed Unit 2 refueling operations being conducted in accordance with Special Operations Procedure D5.2, "Reactor Refueling Operations," Revision 23. The inspectors noted formal communications and attentive operators in the control room, containment, and spent fuel pool areas throughout refueling operations. The fuel transfer log was updated on a step-by-step basis and properly maintained. The inspectors verified that the correct refueling boron concentration existed prior to beginning and throughout refueling operations. Good foreign material exclusion controls were observed in the vicinity of the reactor vessel and cavity.

c. <u>Conclusions</u>

All normal plant operations, as well as Unit 2 refueling operations, were conducted well, without significant problems. The licensee identified two equipment isolation tag errors associated with the Unit 2 refueling outage that, while not safety significant, were caused by inattention-to-detail on the part of the operators attaching the tags. Subsequent inspector reviews found no indications of programmatic equipment isolation problems.

O1.2 Unit 1 Negative Flux Rate Trip

a. Inspection Scope (IP 71707)

On October 29, 1998, Unit 1 experienced a negative flux rate reactor trip from full power. The inspectors reviewed the initial operator response to the trip and the subsequent operator actions to place the plant in a stable condition. The inspectors also evaluated the response of safety-related equipment and the licensee's troubleshooting efforts to determine the cause of the event.

b. Observations and Findings

The licensee determined that the trip was caused by control rod G3 dropping into the core. The response of the operators was good in identifying the cause of the trip and taking immediate corrective actions to place the plant in a safe condition. Throughout the event, safety-related equipment functioned as required. The operators took appropriate action to control the rate of cooldown of the reactor and maintained the unit in a stable hot shutdown condition while troubleshooting was performed to determine the cause of the dropped rod. The troubleshooting and repair efforts are described in more detail in Section M2.2 of this report.

The licensee reported the trip to the NRC in accordance with 10 CFR 50.72 on October 29, 1998, and issued followup Licensee Event Report (LER) 50-282/98016 (1-98-16) on November 24. The LER is closed in Section O8.4 of this report.

c. Conclusions

The operators took prompt, effective actions to place the Unit 1 reactor in a safe condition until the cause for the negative flux rate reactor trip was determined.

O1.3 Unit 1 Transition to and Restoration from Reduced Reactor Coolant Inventory Operations

a. Inspection Scope (IP 71707)

Subsequent to the Unit 1 reactor trip, a small leak was identified on the 11 steam generator cold leg manway. The licensee made a conservative decision to cool down the reactor plant and reduce reactor coolant system (RCS) inventory to make repairs. The repair efforts are discussed in Section M2.1 of this report. The inspectors observed the entry into and the recovery from Unit 1 reduced inventory operations. This included observing portions of the following evolutions: filling the RCS, draining to 30 percent pressurizer level, draining to 1 foot below the reactor flange, draining to the top of the hot leg, maintaining the reactor plant in a reduced inventory status, venting the RCS, and the restoration of the reactor coolant system to normal inventory conditions. Reference material used during this inspection included:

- Operating Procedure 1C4.1, “RCS Inventory Control Pre-Refueling,” Revision 6;
- Special Operating Procedure 1D2, “RCS Reduced Inventory Operation,” Revision 7;
- Operating Procedure 1C1.6, “Shutdown Operations - Unit 1,” Revision 8; and
- Special Operating Procedure 1D8, “Filling and Venting the Reactor Coolant System,” Revision 11.

b. Observations and Findings

The inspectors attended the pre-job briefings for establishing RCS level at one foot below the reactor vessel flange, and for a subsequent draining evolution to establish RCS level to just below the top of the hot leg piping. The briefings were thorough, with pertinent information discussed. The inspectors noted that special emphasis was placed on clearly identifying the RCS drain and vent paths, the use of multiple indications for system response verification, that operators should question any unusual indication, and that good communications were expected.

For each of the draining evolutions, the normal operating crew was supplemented by additional personnel. Those personnel included a senior reactor operator (SRO) assigned to manage the draindown, a reactor operator (RO) to control the draindown, an operator stationed in containment to watch RCS level and communicate with the control room, an operator to monitor chemical and volume control system hold-up tank levels during draining, operators stationed in containment to operate valves and pumps as required, and an instrument and controls technician to assist operators conducting the draindown. The draindowns were conducted in a slow, controlled manner. Communications of status, required actions, and expected indications, both among the operators in the control room and between the control room and containment operators, was excellent.

For filling from the top of the hot leg to the 30 percent pressurizer level, the inspectors verified RCS loop, reactor vessel, and pressurizer vent paths existed. The inspectors verified that a pre-job briefing had been held and that the shift crew understood what the expected volumes to be charged to the RCS were. When questioned by the inspectors, the shift crew also demonstrated a good understanding of the expected inventory changes in the reactor vessel, RCS loops, steam generator channel heads, pressurizer, and the volume control tank for the filling evolution. Boric acid addition pathways and blended flow concentrations were also checked to ensure that the filling evolution would not cause a decrease in the RCS boric acid concentration and a resultant addition of positive reactivity. The actual filling evolution occurred with no discrepancies.

c. Conclusions

Unit 1 draining and refilling evolutions were conducted in a slow, controlled, and deliberate manner. Whenever RCS inventory changes were being made, extra personnel were assigned to the operating crew, communications were formal, vent and drain paths were carefully scrutinized, and operators frequently checked diverse level indications.

O1.4 Unit 2 Reactor Trip and Transition to Refueling Shutdown for Cycle 19

a. Inspection Scope (IP 71707)

The inspectors observed a scheduled Unit 2 shutdown on November 9, 1998, for the cycle 19 refueling outage. During the downpower, a turbine trip caused a reactor trip from 22 percent power. Once plant conditions were stabilized, the inspectors observed portions of the transition from hot shutdown to refueling shutdown conditions. Reference material used during this inspection included:

- Operating Procedure 2C1.4, "Unit 2 Power Operation," Revision 16;
- Operating Procedure 2C1.3, "Unit 2 Shutdown," Revision 42;
- Special Operating Procedure 2D2, "RCS Reduced Inventory Operation," Revision 7;
- Emergency Operating Procedure (EOP) 2E-0, "Unit 2 Reactor Trip Or Safety Injection," Revision 16;
- Emergency Operating Procedure 2ES-0.1, "Unit 2 Reactor Trip Recovery," Revision 12;
- WO 9812104, Latch Turbine to Check Equipment Condition";
- WO 9809805, "Heater Drain System Levels and Valves Part A Calibration";
- WO 9809806, "Feedwater Heaters, Moisture Separators, Reheater Drain Tank Levels Part C Calibration";
- WO 9812527, "Replace Solenoid Valve SV-33011 Found Sticking During Calibration"; and
- WO 9812692, "Valve CV-31043 Sticks Badly and Diaphragm Leaks."

b. Observations and Findings

The Unit 2 power reduction was conducted normally, with a load reduction rate of one percent per minute. Plant equipment responded as expected and control room operators remained attentive to changing plant conditions. The RO and lead RO maintained good control over trainees manipulating plant controls. The operators also maintained good awareness and control of reactor temperature deviations, control rod positions, axial flux deviation limits, boric acid additions, feedwater system transients, and steam generator levels. An unexpected turbine trip occurred at 22 percent reactor power which caused the reactor to trip, as designed.

The inspectors observed good crew response to the reactor trip. Emergency Operating Procedure 2E-0 was immediately referenced and a transition rapidly was made to EOP 2ES-0.1. The shift supervisor provided effective leadership during the trip response and frequently received plant condition information from the control room operators. During the performance of EOP 2ES-0.1, Step 7, the reactor operator noted that rod position indicators for control rods G19 and C5 did not indicate fully inserted. The operators borated 250 gallons for each of the control rods as required by the procedure. A few minutes later all the control rods indicated fully inserted. The individual rod position calibrations and temperature transients following the reactor trip had apparently resulted in the control rods initially not indicating a fully inserted position. Subsequent cooldown to less than 200 degrees Fahrenheit (°F) in preparation for the refueling outage occurred normally, with no discrepancies.

The inspectors attended the pre-job briefing for draining from one foot below the reactor vessel flange to the top of the hot leg to allow the installation of steam generator nozzle dams. The briefing was very detailed and all personnel participating in the evolution were present. A member of the training department discussed the vent and drain paths and the general superintendent of plant operations emphasized management expectations on procedural adherence and communications. The shift supervisor in charge of the evolution discussed personnel assignments and responsibilities, the use of diverse level and inventory indications, expected draining times, contingency actions, past problems, and the need to minimize distractions in the control room.

The inspectors observed the draining evolution from the control room and containment. All personnel in containment were attentive and at their required station. Each had a copy of the procedure applicable to their actions in-hand. Communications used during the evolution were formal and complete. Operators in the control room frequently checked diverse level indications and looked for correlations between hot leg ultrasonic instrument levels, chemical and volume control system hold-up tank levels, reactor vessel standpipe levels, reactor coolant drain collecting tank level, reactor coolant drain tank discharge pump run times, and reactor vessel expanded emergency response computer system indicated level. The evolution was slow, deliberate, and well controlled. No discrepancies were noted.

The licensee conducted a detailed investigation into the cause of the unexpected turbine trip. Using WO 9812104, the licensee successfully relatched the turbine on the evening of November 9, and noted no turbine trip or control system malfunctions. Further investigation, led by the general superintendent of safety assessment, methodically examined all possible causes of a turbine trip. The only turbine trips that were not eliminated as potential causes included a high-high level trip in 22B low pressure feedwater heater or an intermittent component failure. Work Orders 9809805 and 9809806 were issued to calibrate some of the low pressure feedwater heater level switches. Although the calibrations were not complete at the end of this inspection period, personnel calibrating the level switches had found at least one sticky solenoid valve (WO 9812527) and one sticky drain cooler condenser dump valve with a leaking air diaphragm (WO 9812692).

The licensee reported the reactor trip to the NRC in accordance with 10 CFR 50.72 and intended to issue LER 50-306/98005 (2-98-05) as a written followup. The inspectors will review the LER when it is issued.

c. Conclusions

Operations personnel maintained good awareness and control of Unit 2 plant equipment and trainees during a routine refueling outage shutdown. The crew responded effectively to an unexpected turbine trip/reactor trip which occurred during the shutdown at 22 percent power. Although not complete at the end of the inspection period, the licensee investigation into the cause of the turbine trip was reasonable and methodical. Operations with reduced reactor coolant inventory preceding refueling operations were well managed.

O1.5 Unit 1 Reactor Startup and Return to Full Power Operation

a. Inspection Scope (IP 71707)

During November 17-18, 1998, Unit 1 was restarted and returned to full power operation following the negative flux rate trip of October 29, 1998 (Section O1.2). The inspectors observed portions of the RCS heatup, equipment realignment for power operation, control rod withdrawal to criticality, and power ascension. The following documents were reviewed as part of this inspection:

- Operating Procedure 1C1.2, “Unit 1 Startup Procedure,” Revision 20;
- Operating Procedure 1C1.4, “Unit 1 Power Operation,” Revision 16;
- Operating Procedure C1B, “Appendix - Reactor Startup,” Revision 6;
- Form 1224, “Crew Meeting Review of Noteworthy Event/Near Miss/Change,” dated November 18, 1998;
- NCR 19983137, “Quadrant Power Tilt Ratio Alarm Comes In on Emergency Response Computer System Down to Zero Power”;
- Alarm Response Procedure C47013-0403, “Computer Alarm Flux Tilt Check Typer,” Revision 15; and
- Dedicated Alarm Printer Log, November 18, 1998.

b. Observations and Findings

For the reactor startup and approach to criticality, the pre-job briefing was adequate and included a complete review of all precautions. Duties of each individual member of the operations team were clearly designated. Two extra ROs and one extra shift supervisor were assigned. This allowed the operators actually performing and supervising the approach to criticality to focus solely on that evolution. Reactor startup and approach to criticality were conducted in a slow, deliberate, and controlled manner. No significant discrepancies were noted. Criticality was achieved near the predicted point and was properly identified and recorded. Control room communications were formal. While increasing turbine speed, a turbine electrohydraulic control problem was encountered. Reactor power was held at 6 percent for approximately the next 16 hours while repairs were completed.

On November 18, 1998, the inspectors noticed annunciator 47013-0403, "Computer Alarm Flux Tilt Check Typer," alarming. The inspectors asked the RO the reason for the alarm. The RO replied that the alarm had been occurring intermittently since shortly after the reactor had reached criticality. He stated that the alarm was common at low reactor power levels but routinely cleared as power increased. Although the RO had previously reviewed the alarm response procedure, he reviewed the actions again with the inspector. The inspectors noted that the second initial action of the alarm response procedure referred the operators to Technical Specification (TS) 3.10.C, "Quadrant Power Tilt Ratio."

Based on the requirements of the alarm response procedure, the inspectors reviewed TS Sections 3.10.C.1 and 3.10.C.2. The inspectors noted that requirements to restrict core power level and to bring the reactor to hot shutdown if the flux tilt recurred intermittently for a sustained period of 24 hours applied to the current reactor condition. Following discussions by the inspectors with the shift supervisor and superintendent of nuclear engineering, the licensee entered the Limiting Condition for Operation (LCO) action requirement time limits associated with TSs 3.10.C.1 and 3.10.C.2. The turbine problem was subsequently resolved, reactor power was increased, and the flux tilt alarm was cleared before the action time limit had expired.

The inspectors reviewed the Dedicated Alarm Printer Log and noted that the first C47013-0403, Computer Alarm Flux Tilt Check Typer alarm occurred at 12:12 a.m. on November 18, 1998. The alarm continued to occur intermittently every three to four minutes for the next seven hours before the inspectors noticed the flux tilt alarm, raised a concern, and the LCO action statement time requirement was tracked. The C47013-0403 flux tilt alarm was computer-based and programmed to occurred when the difference between the highest and average power of the upper or lower excore neutron detectors varied by more than two percent. The computer alarm setpoint, however, was programmed to vary linearly with reactor power. At low reactor power levels, normal variances in flux distributions caused the computer alarm setpoint to be exceeded when, in fact, no flux tilt conditions actually existed in the core. A separate, nuclear instrument flux tilt alarm function also monitored core flux tilt conditions. The nuclear instrument-based flux tilt alarm was not occurring at the time of the inspectors' observation and was, by design, disabled below 50 percent reactor power.

The licensee initiated NCR 19983137 to document its review of the finding. At the end of the inspection period, the investigation indicated that the flux tilt alarm provides no real value at very low powers. In fact, the TS was unclear because of ambiguous wording as to whether the flux tilt specification even applied when below 50 percent power. In a letter dated December 10, 1998, the licensee requested an interpretation of the flux tilt TS from the NRC Office of Nuclear Reactor Regulation. Nevertheless, given the existing wording of the TS, the operators exhibited a lack of TS awareness, until the inspectors raised a concern, by not tracking the flux tilt alarms to ensure that the action time limit was not exceeded.

As one corrective action, all operations crews were trained concerning the expected actions for flux tilt alarms at low power. This action was adequate.

The safety significance associated with the inspectors' observation was low. The computer flux tilt alarms were caused by normal variances in neutron flux patterns at low power levels and a low alarm setpoint. No actual flux tilt conditions existed. In addition, the 24-hour time limit was not exceeded. However, the operating crew exhibited a lack of awareness of TSs by not entering the applicable LCO statements until the inspectors raised a concern.

c. Conclusions

The Unit 1 reactor startup and power ascension were performed in a safe and conservative manner. However, two operating crews exhibited a lack of Technical Specification awareness by not applying the applicable Limiting Condition for Operation action statement time requirements associated with intermittent flux tilt alarms, until the issue was raised by the inspectors.

O6 Operations Organization and Administration

O6.1 Management Control of Dual Unit Outage

a. Inspection Scope (IP 71707)

The inspectors monitored plant management's control and prioritization of activities during the dual unit outage, which occurred from November 3 to November 17, 1998.

b. Observations and Findings

The inspectors noted that prior to the dual unit outage beginning the Operations Committee (onsite review committee) met and established clear priorities for managing activities with both units in an outage. Namely:

- Unit 2 would not commence the planned shutdown for the cycle 19 refueling outage if Unit 1 was still in reduced RCS inventory conditions; and

- once the Unit 2 shutdown had commenced, resources would remain focused on that unit until the turbine rotor replacement, D6 emergency diesel generator five-year preventive maintenance, and steam generator eddy current work had started.

Following the Unit 2 shutdown, plant management and the outage planning staff met twice daily to evaluate the status and plans for each unit. Once the Unit 2 major outage tasks had begun, priorities shifted to Unit 1 recovery and return to full power operation.

c. Conclusions

Plant management effectively controlled and prioritized activities during a challenging and unexpected dual unit outage.

O7 Quality Assurance in Operations

O7.1 Safety Audit Committee (SAC) Meeting Summary

The licensee SAC held its semi-annual meeting on October 29, 1998. The inspectors attended and observed portions of the meeting. Major topics discussed and reviewed by the members included: quality assurance audits conducted since the last SAC meeting, the status of the steam generators for both units, the progress of implementing the plan to address the year 2000 computer issues, the rod control cable connector problem, and TS changes since the last SAC meeting. The SAC meeting included the required quorum of appropriately qualified individuals and effectively performed the reviews outlined in TS Section 6.

O8 Miscellaneous Operations Issues (IP 92700)

O8.1 Plastic Labeling Material Melting on High Temperature Pressurizer Sample Lines

a. Inspection Scope (IP 71707)

In the Unit 2 containment, the inspectors noted melted plastic labeling material on the pressurizer liquid space sample line. The inspectors reviewed the implications of the material on the sample line with respect to surface contamination and potential chemical-induced cracking of the stainless steel valve and piping components. The following documents were reviewed as part of this inspection:

- Administrative Work Instruction (AWI) 5AWI 3.10.5, “Plant Equipment Labeling,” Revision 7;
- Material Safety Data Sheet (MSDS) 000037, “Magnum (R) AG 700 ABS,” effective date October 9, 1990;
- Form 1224, “Crew Meeting Review of Noteworthy Event/Near Miss/Change,” dated December 1, 1998; and
- Drawing NF-39238, “Flow Diagram Sampling System Reactor Plant,” Revision Y.

b. Observations and Findings

The inspectors noticed that the plastic labeling material on pressurizer liquid sample space valves 2SM-7-2 and 2SM-14-2 was discolored and burned. Further investigation revealed that a small amount of the labeling material had adhered to one of the valve bodies and adjacent tubing and dripped onto the floor below the valves. The inspectors obtained a copy of the applicable MSDS and noted that at temperatures above 572°F, the labeling material decomposed to acrylonitrile and hydrogen cyanide. Information obtained from Drawing NF-39238 indicated that the temperature of the pressurizer liquid sample ranged from 550 to 650°F. The inspectors contacted the system engineer and expressed concern for potential chemical-induced valve body and sample line cracking due to the decomposition products.

The system engineer performed an independent walkdown of other sample lines and noted a similar melted plastic tag on the pressurizer steam space sample valve, 2SM-7-1. In the case of 2SM-7-1, it appeared that a red safeguards hold tag had completely melted against the valve body and yoke. The licensee performed various chloride, fluoride, and sulfate analysis on 2SM-7-1 before and after removing the melted plastic material. All samples indicated chloride, fluoride, and sulfate results only in the parts per billion range; too low to cause metallurgical problems. A dye penetrant check of the 2SM-7-1 valve body and six inches of adjacent piping was performed. No surface cracks or indications were noted. Similar testing on valves 2SM-7-2 and 2SM-14-2 yielded the same results. Taken together, the dye penetrant and chemical sample results resolved the concerns.

To prevent similar events, training was conducted for all operating crews. The training discussed the melting of the 2SM-7-1 safeguards hold tag and the need to ensure that safeguards and identification tags attached to components are hung so they do not melt.

Per 5AWI 3.10.5, Step 6.2.8, plastic label materials should be approved for the plant location and environment in which they are used. High temperatures should be avoided unless the labeling material was suitable for the specific high temperature application. Although not used for this application, stainless steel tags, in place of plastic tags, were allowed for high temperature environments.

c. Conclusions

The licensee adequately investigated and evaluated NRC concerns with the effects of chemicals from melted plastic tags on stainless steel piping and valves.

O8.3 (Closed) LER 50-282/98008 (1-98-08): Reactor Trip Initiated by a Negative Flux Upon Control Rod Insertion Following Failure of Control Rod Drive Cable. The cause and corrective actions for this event were the same as for LER 1-98-16 discussed in the next section. Since all corrective actions have been completed, the LER is closed.

O8.4 (Closed) LER 50-282/98016 (1-98-16): Negative Flux Rate Reactor Trip Upon Control Rod Insertion Following Failure of Control Rod Drive Cable. The cause and corrective actions for the event are discussed in Sections O1.2 and M2.2 of this report. Since all the corrective actions were either complete or captured in a near-term Unit 2 outage schedule, the LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

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

The inspectors observed all or portions of the following maintenance and surveillance activities. Included in the inspection was a review of the surveillance procedures (SPs), test procedures (TPs), PM procedures, or WOs listed, as well as the appropriate USAR sections regarding the activities. The inspectors verified that the SPs for the activities observed met the requirements of the Technical Specifications except where noted. The following reference material was reviewed by the inspectors:

- SP 1102, “11 Turbine-Driven AFW [Auxiliary Feedwater] Pump Monthly Test,” Revision 63;
- SP 1226A, “Containment Hydrogen Monitor Monthly Test,” Revision 8;
- SP 1226B, “Containment Hydrogen Monitor Quarterly Calibration,” Revision 8;
- SP 2226B, “Containment Hydrogen Monitor Quarterly Calibration,” Revision 7;
- SP 2092A, ”Safety Injection Check Valve Test (Head Off) Part A: Hi Head SI [Safety Injection] Flow Path Verification,” Revision 21;
- SP 2102, “22 Turbine-Driven AFW Pump Monthly Test,” Revision 54;
- PM 3107-2, “121 Cooling Water Pump Annual Inspection,” Revision 15;
- PM 3132-1-22, “22 Turbine Driven Auxiliary Feed Pump Refueling Inspection,” Revision 30;
- TP 2834, “Unit 2 - Containment Coating Inspection,” Revision 0;
- WO 9713081, “P3107-3 Cooling Water Pump Discharge Check Valve Inspection”;
- WO 9807247, “Preventative Maintenance on Main Steam Isolation Valve CV-31116”;

- WO 9811353, “Clean Unit 1 Condenser Innerpass Tubes and Amertap Screen”; and
- WO 9812723, “Check/Adjust D6 Generator Alignment.”

b. Observations and Findings

- The inspectors chose to observe AFW system testing based on the impact that the AFW has on reactor safety, as illustrated by the Prairie Island probabilistic risk assessment.

  The inspectors observed the pre-job briefing and performance of testing in accordance with SP 1102, “11 Turbine-Driven AFW Pump Monthly Test.” The testing exercised a number of valves associated with the pump and verified that valve stroke times were acceptable, verified that the 11 AFW pump started and generated the correct discharge pressure, verified pump and turbine lube oil temperatures and levels were correct during operation, and verified that vibration data were within the acceptable range.

  The inspectors observed the testing in the AFW pump room. The inspectors noted good control of the evolution and that all equipment observed operated correctly. The inspectors also observed that the overall material condition of the 11 turbine-driven AFW pump was good. The inspectors noted that there was a small leak of approximately 3 to 4 drops per minute issuing from the discharge flow orifice flange and brought this to the attention of the system engineer. The system engineer evaluated the leak and determined that it was leakage through the seal weld on the plugged pressure tap on the upstream flange of the 11 AFW pump discharge flow orifice. He concluded that the threaded plugs were capable of holding system pressure, independent of the seal welds, so the leakage could not increase to a high enough level to have a noticeable effect on the pump’s flowrate and that operability of the pump was not affected. The system engineer wrote WO 9811742 to direct the repairs. The engineer’s evaluation was documented in NCR 19982727.

  Immediately following the test of the 11 AFW pump, the 22 turbine-driven AFW pump was tested in accordance with SP 2102, “22 Turbine-Driven AFW Pump Monthly Test.” The testing of both pumps was conducted by the same operators. During the conduct of the SP, the inspectors focused on the control of the evolution from the control room and the communications demonstrated during the test. The inspectors noted good control of the evolution by the control room and excellent three-part communications used by the operators. The inspectors also observed that the overall material condition of the 22 turbine-driven AFW pump was good and that all components observed during the performance of the SP operated as required.

- On November 3, 1998, the inspectors noticed that a lead nuclear plant service attendant had stopped work activities associated with WO 9811353, “Clean Unit 1 Condenser Innerpass Tubes and Amertap Screen,” and with Maintenance Procedure D24.4, “Condenser Tube Cleaning With Air and Water,” Revision 0.

The attendant was a member of the site safety department and had stopped the work after noticing that the confined space entry permit associated with the job had not been properly completed. Work had been in progress for about one hour.

The attendant noticed that while all air monitoring results had been properly recorded and were within specifications, sections of the confined space entry permit had not been properly filled out. The attendant stopped the work and requested a maintenance supervisor report to the job site and complete the confined space entry permit. The inspectors verified that the required ventilation, personnel protection and standby personnel requirements were in place and that the issue had been one of documentation only. No NRC requirements were violated.

- The inspectors observed containment hydrogen monitor testing in accordance with SPs 1226A, 1226B, and 2226B. A new technician performed SPs 1226A and 1226B under the supervision of a more experienced instrumentation and controls staff member. The more experienced staff member maintained good control of the trainee and frequently stopped the surveillance to explain details and vulnerabilities associated with the hydrogen monitoring system. Good self-checking techniques were demonstrated during SP 1226A, Step 7.1.4, when it was noted that an error had been made in previously entering data associated with the Train ‘A’ containment hydrogen detector, 1XE-719. The mistake was corrected and all subsequent hydrogen monitor surveillances completed satisfactorily.

- The inspectors observed full flow testing of the 21 and 22 SI pumps in accordance with SP 2092A. The test included running of each SI pump with various discharge paths and flow rates to generate data to compare with pump performance curves. The surveillance also met TS testing requirements to ensure cold leg and vessel injection flows are balanced and that the four injection paths plus recirculation flow did not exceed pump runout. The inspectors observed that the operators methodically performed the testing and collected the required data. The system engineer was present throughout the testing. The inspectors verified that the data collected for each SI pump met the pump performance curves.

  Steps 7.17.5 and 7.37.5 required the operators to verify that with all four cold leg and reactor vessel injection paths open and recirculation flow included, the pump runout limit of 819 gallons per minute (gpm) was not exceeded. When this configuration was established for the 21 and 22 SI pumps, the flows exceeded the pump runout limits and were recorded as 822 gpm and 823 gpm, respectively. The system engineer subsequently wrote WO 9812402 to direct evaluation and correction of the flows as necessary; however, the problem had not been resolved by the end of the inspection period. The system engineer stated that the SI pumps would be rerun under the same full flow conditions and throttle valves adjusted as necessary to reduce flows below runout limits.

c. Conclusions

The 13 routine maintenance activities and surveillance tests observed by the inspectors were performed well and demonstrated good communications and coordination between the control room and personnel performing the work. An astute member of the site safety department stopped work associated with Unit 1 condenser waterbox cleaning when she noticed that the confined space entry permit did not contain complete documentation concerning safe personnel working conditions.

M1.2 Unit 2 Reactor Vessel Head and Upper Internals Removal During the Cycle 19 Refueling Outage

a. Inspection Scope (IP 62707)

The inspectors observed the Unit 2 reactor vessel head and upper internals removal on November 17 and 18, 1998. The following documents were reviewed as part of this inspection:

- Special Operations Procedure D5.2, "Reactor Refueling Operations," Revision 23;
- Maintenance Procedure D3, "Reactor Vessel Head Removal," Revision 38;
- Maintenance Procedure D58.2.9, "Unit 2 Reactor Vessel Head Removal," Revision 0;
- Maintenance Procedure D58.2.5, "Unit 2 Reactor Upper Internals Removal," Revision 0; and
- WO 981008, "Perform Weld 1 and Ligament Manual Examinations on the Reactor Vessel."

b. Observations and Findings

The inspectors attended the pre-job briefings for both the reactor vessel head and upper internals removal. The briefings were led by a maintenance supervisor and included the operations, health physics, maintenance, and contractor personnel involved in the evolution. Both briefings were comprehensive and included discussions of individual roles and responsibilities, expected load cell weight indications, safe heavy load paths, a general procedure outline, expected dose rates, health physics department actions, communications, precautions and limitations, and related historical events.

During movement of the reactor vessel head from the vessel to the storage stand, the inspectors observed that refueling integrity was in effect, the SRO in containment was in constant communication with the control room, and nuclear instrument source range counts were audible in containment. The inspectors noted that in order to be consistent with recent load drop analysis (Inspection Reports 50-282/98015(DRP); 50-306/98015(DRP), Section E3.1 and 50-282/98018(DRP); 50-306/98018(DRP), Section E8.2), the reactor vessel head was not raised above the 765' elevation. The inspectors also observed the ultrasonic examination of the reactor vessel ligaments in accordance with WO 9810081. The inspection was performed manually and provided adequate coverage of the area of concern.

During movement of the reactor vessel head, two minor problems occurred. The first was when the reactor vessel head was lifted one inch above the upper internals in accordance with D58.2.9, Step 7.2.1. The expected load cell reading was approximately 141,500 pounds. The actual load cell reading was 166,300 pounds. The SRO in containment, reactor vessel system engineer, heavy loads system engineer, and rigging leader discussed the difference and considered the possibility that at least some control rods might still be attached to the reactor vessel head. They concluded that since the reactor vessel head appeared clear by visual examinations, exhibited freedom of movement and no binding on the guide studs, radiation levels adjacent to the head remained constant, and source range nuclear instrument counts had not changed, all control rods were unlatched and the lift could proceed. Later investigation revealed that the Unit 1 digital readout meter had mistakenly been combined with the Unit 2 load cell during D58.2.9, Step 7.1.9. The load cell and readout unit were matched pairs that needed to be used together to provide an accurate reading. The heavy loads engineer subsequently stated that all heavy load procedures utilizing the digital readout meter and load cell combinations would be revised to include greater detail and prevent component mismatches in the future. The revisions were expected to be complete by the end of 1998.

The second discrepancy occurred during the performance of maintenance procedure D58.2.9, Temporary Change Notice 1998-0206, Steps 7.2.2, C.1 and C.2. The reactor vessel head was stationary, approximately 18" to 24" above the upper internals, with the ultrasonic ligament inspection about to begin. The inspectors and the SRO in containment noted a sudden step increase in the source range nuclear instrument audible count rate. This was one possible indication of an inadvertent criticality accident. The SRO immediately contacted the control room and asked if any changes or manipulations had just been made. The control room replied that the audible counts channel had just been changed from the N32 to N31 source range nuclear instrument in accordance with Step 7.2.2, C.1.1 and that they had not informed containment personnel in advance.

The remaining reactor vessel upper internals removal activities occurred with no discrepancies. Safe load paths were followed, upper internal weights indicated expected values, and refueling integrity was maintained during the lift. A remote underwater camera provided a good verification that no control rods or fuel were being withdrawn with the upper internals.

c. Conclusions

Unit 2 reactor vessel head and upper internals removal was accomplished in an acceptable manner. However, two minor attention-to-detail discrepancies occurred when the reactor head was lifted. One concerned using an unmatched digital readout meter with a load cell and the other was failure of the control room to communicate to containment personnel when changing containment audible source range nuclear instrument channels.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Cold Leg Manway Leak on the 11 Steam Generator

a. Inspection Scope (IP 62707)

The inspectors reviewed the events leading to the identification of the RCS leak on the 11 steam generator cold leg manway and the subsequent corrective actions performed by the licensee to repair the leak. As part of the inspection, the inspectors reviewed NCRs 19982820 and 19983004.

b. Observations and Findings

On or about October 19, 1998, to support routine maintenance efforts, a portable air sample was drawn on Unit 1 containment. The air sample results identified low levels of iodine-133. An analysis of the information provided by the containment air particulate monitor, R11, revealed a slightly increasing activity trend. There was no corresponding increase in containment gaseous activity levels or humidity. Based on the particulate activity level indicated by R11, the health physics department determined that an approximate one gallon per day reactor coolant leak existed in Unit 1 containment. An at-power containment entry was made on October 22, 1998, and no obvious source of coolant leakage was found.

On October 28, with R11 reading at a slightly elevated, but stable level, and with new information that the containment A sump pump had been operating more frequently, the licensee determined that the leak was more in the range of 30 gallons per day. This value was well within the allowed TS limit for unidentified RCS leakage.

On October 29, two additional at-power containment entries were made. The first entry was a more detailed containment inspection, focusing on accessible portions of the reactor vessel head and reactor coolant pump vaults. This inspection did not reveal any definitive source of RCS leakage. The second entry was to verify the proper operation of the sump pump for the A containment sump. This inspection verified the proper operation of the sump pump and identified that there was boric acid residue on and around the 14 fan coil unit and an increased amount of clear water draining from the 14 fan coil unit to the A containment sump. An analysis of the water in the A containment sump revealed the presence of long-lived fission products and boric acid in concentrations less that RCS concentrations.

The licensee determined that the presence of long-lived fission products in containment sump A, combined with the presence of boric acid crystal on and increased condensation from the 14 fan coil unit, indicated that there was a small primary steam leak in the 11 reactor coolant pump vault. A fourth at-power containment entry, with Unit 1 power reduced to approximately 10 percent, was scheduled for October 31, but was not performed because of the Unit 1 trip on October 29 (Section O1.2). A more detailed inspection of the vault was completed on October 30 and identified boric acid residue around the steam generator cold leg manway. The licensee decided to remove the mirror insulation from both the 11 and 12 steam generator hot leg and cold leg manways to inspect for leakage. After the insulation had been removed, no signs of leakage were noted on the 12 steam generator manways. However, an inspection of the 11 steam generator cold leg manway identified about four pounds of boric acid residue at the manway cover gap as well some boric acid residue deposited in the mirror insulation that was removed from the manway cover. Inspection of the hot leg manway identified some points where leakage may have been starting, but no build-up of boric acid residue was present.

The inspectors followed the root cause analysis efforts performed to determine the cause of the manway leakage. Some of the results of the analysis are listed below.

- The gap measurements for both the 11 and 12 steam generator hot and cold leg manways were within specification.

- Slight but insignificant movement on 4 of the 7 bolts of the 11 steam generator cold leg manway was obtained during a torque test. No movement was obtained on the 12 steam generator manway bolts.

- The phonographic-like finish on the gasket seating surfaces for the steam generator manway covers was smoother than the surface roughness recommended by the vendor.

- The gasket compression was considered to be adequate based on the as-found cover gap measurements.

- Bolt length measurements prior to removal were not possible due to the roughness of the bolt heads.

The system engineer responsible for the steam generators informed the inspectors that the most probable root cause of the leakage was a combination of Flexitallic gasket deterioration and inadequate gasket surface phonographic-like finish.

Corrective actions were taken to repair both of the manways for the 11 steam generator. A phonographic-like finish was machined onto the hot leg and cold leg manway gasket seating surfaces, establishing the preferred surface roughness. During the restoration of the cold leg manway, a new manway cover, diaphragm, and bolts were installed. During the restoration of the hot leg manway, a new diaphragm and bolts were installed. After the manway covers had been installed, satisfactory gap measurements and bolt elongation measurements were obtained indicating sufficient gasket compression and proper bolt torquing. In addition to establishing the preferred roughness for the steam generator manway gasket seating surfaces, the licensee also machined the pressurizer manway gasket seating surface.

c. Conclusions

The licensee took adequate actions to identify the source of a Unit 1 RCS leak. Once the location of the leak was identified as the cold leg manway for the 11 steam generator, a conservative decision was made to reduce RCS inventory and make repairs.

Appropriate engineering oversight and maintenance resources were utilized to effectively repair the 11 steam generator hot and cold leg and the pressurizer manways.

M2.2 Problem Identification and Corrective Actions for Dropped Control Rod G3

a. Inspection Scope (IP 62707)

The inspectors reviewed the troubleshooting efforts to identify what caused control rod G3 to drop into the core during full power operations of Unit 1 and the actions taken by the licensee to prevent reoccurrence. The inspectors also reviewed the causes of and corrective action performed for two other occurrences of dropped control rods in the previous 17 months. As part of this inspection, the inspectors reviewed the following documents:

- WO 9811799, "Investigate and Repair Blown Fuse Indication on G3";
- WO 9811804, "Unit 1, Rod G3, Lift Wires and Megger";
- WO 9811816, "Unit 1, Rod G3, Megger at Pool Wall";
- WO 9811839, "Unit 1, Rod G3, Megger at CRDM [control rod drive mechanism] on Head";
- WO 9811898, "RPI [rod position indication] Coil Resistance Checks";
- WO 9811900, "CRDM Coil Integrity Check";
- WO 9811888, "Unit 1 RPI and CRDM Cable Replacement";
- WO 9811889, "Unit 1 CRDM and RPI Replacement Post Maintenance Tests";
- NCR 19982772, "Unit 1 Rod G3 Drop Causes Reactor Trip, Suspected Bad CRDM Cable"; and
- NCR 19981221, "Shorted G7 Stationary Gripper Coil Resulted in Reactor Trip on Unit 1 6/5/98."

b. Observations and Findings

On October 29, 1998, the Unit 1 reactor scrammed from 100 percent power because of a negative flux rate trip signal. The signal was generated when control rod G3 dropped into the core.

On two other occasions in the last 17 months, the Unit 1 reactor tripped on negative flux rate because of dropped control rods. The first trip occurred on June 2, 1997, and was documented in Inspection Report 50-282/97011(DRP); 50-306/97011(DRP), Section M1.1. The second trip occurred on June 5, 1998, and was documented in Inspection Report 50-282/98010(DRS); 50-306/98010(DRS), Section E1.1. In each case, a faulted CRDM patch cable connector was determined to be the root cause of the event, but the failure mechanism remained undetermined. Following the most recent dropped rod event, initial troubleshooting revealed that both the positive and negative fuses for the G3 control rod stationary grippers were blown. A series of work orders was written and, during the associated work activities, the licensee determined that the fault was also located in the CRDM patch cable (the cable between the top of the reactor cavity wall and the vessel head) connector for G3 control rod.

The licensee determined that each of the dropped rod events could be attributed to a fault between the stationary gripper coil leads and/or a ground fault near a CRDM connector. Following the second dropped rod event, the licensee enlisted the aid of Westinghouse, the cable vendor, to determine the cause of the G7 CRDM patch cable failure. The final report from the Westinghouse failure analysis concluded, in part, that a chemical analysis of the deposits found on the Hypalon jacket and within the G7 connector indicated that a breakdown of the Hypalon rubber occurred during reactor operation which produced hydrogen chloride vapors. The vapors in conjunction with some water created a conductive path that shorted pin A to pin B in the patch cord connector. However, the licensee could find no credible source for the water because of the high temperatures and ventilation present near the location of the G7 connector. The licensee identified that it was possible that the moisture found in the patch cable connector was a product of the hydrogen chloride vapors reacting with the aluminum connector shell. Neither the licensee nor Westinghouse was able to identify an actual external source for the water.

The corrective action taken to prevent similar failures of CRDM patch cable connectors, and subsequent rod drop events, was to replace all of the RPI and CRDM patch cables from the reactor vessel head to the pool wall. The new cables utilized fiberglass/stainless steel braided cable jackets instead of Hypalon cable jackets and used stainless steel instead of aluminum backshells on the connector assemblies. These new patch cables also had a higher temperature rating. The inspectors verified that all Unit 1 RPI and CRDM head area patch cables were replaced and post-installation testing completed satisfactorily prior to Unit 1 reactor startup. The inspectors also verified that the Unit 2 cables were scheduled to be replaced during the cycle 19 refueling outage. The licensee also planned to evaluate CRDM preventive maintenance options to better predict impending failures and to evaluate methods to provide forced cooling to the CRDM head connector area.

c. <u>Conclusions</u>

The licensee took adequate action to address the repeated CRDM patch cable fault issue. After the second dropped rod event, the licensee took conservative actions to enlist the aid of the CRDM cable vendor to assist in the root cause evaluation of the cable fault and to procure improved CRDM and RPI patch cabling for both units.

M2.3 D6 Emergency Diesel Generator (EDG) Five-Year Preventive Maintenance

a. Inspection Scope (IP 62707)

The inspectors witnessed portions of the maintenance tasks performed on the D6 EDG in accordance with WO 9810427, "D6 Five Year Preventative Maintenance." This was the first time that a Socieitie Alsacienne De Constructions Mecaniques De Mulhouse EDG had been disassembled, inspected, and reassembled in North America.

b. Observations and Findings

The inspectors observed portions of the removal and installation of major engine components, including the cylinder heads, pistons, connecting rods, exhaust and intake manifolds, and fuel oil injectors. All observed activities were performed in accordance with the EDG manufacturer's recommendations and requirements. The inspectors examined the cylinder head condition, cylinder liner wear patterns, piston crown carbon accumulations, piston and oil scraper ring wear, and connecting rod bearing surface wear characteristics associated with the components removed from the D6 EDG, engines 1 and 2. All components exhibited minimal wear and on the majority of the cylinder liners, the initial manufacturing honing patterns were still visible. The piston crowns showed little or no carbon accumulation and all piston and oil scraper rings examined were intact and free to move in their respective piston ring grooves. Connecting rod bearings showed signs of adequate lubrication and exhibited normal wear patterns.

Parts control during EDG disassembly and reassembly was excellent. All parts that were removed from the engines were properly labeled, recorded, segregated, stored, and then retrieved during engine reassembly. Foreign material controls were adequate. The inspectors reviewed the data associated with the high and low temperature jacket cooling water thermostatic temperature control valves. The valves cracked open and went full open at the correct setpoints. The inspectors also observed the torquing of several connecting rod cap bolts. All torquing was performed in accordance with WO 9810427 and the manufacturer's recommendations.

The inspectors observed that the system engineer was frequently present at the job site during all phases of the maintenance. The quality services department also provided extensive coverage of the maintenance activities and trained and qualified two experienced maintenance department individuals as level 1 quality control inspectors. This was in addition to more experienced quality control inspectors who also provided oversight during the maintenance activities. The level 1 maintenance department quality control inspectors were exceptionally effective and vigilant in monitoring maintenance activities. The NRC inspectors viewed the extensive quality control oversight of the D6 maintenance activities as critical since contract laborers, with limited experience on that type of diesel generator, disassembled and reassembled the EDG.

c. Conclusions

The D6 emergency diesel generator five-year preventive maintenance was performed well, with no discrepancies noted by the inspectors. The initiative taken to qualify experienced maintenance personnel as level 1 quality control inspectors to provide extensive coverage during maintenance activities was particularly effective in ensuring successful completion of the maintenance.

M8 Miscellaneous Maintenance Issues (IPs 92700 and 92902)

M8.1 (Open) LER 50-306/98004 (2-98-04): Shield Building Integrity. This LER discussed a condition, identified by the licensee, where recent maintenance on the shield building access doors may have resulted in a breech of shield building integrity for a period of time greater than the 24 hours allowed by TS 3.6.G. A licensee review of maintenance records for the quarterly mechanical door corrective maintenance revealed two instances where work was not signed as complete on the same calendar day that it was begun.

The cause of the event, safety significance, and corrective actions were adequately discussed in the LER. Although the LER stated that shield building integrity may have been breached for a period of time greater than allowed by TS 3.6.G, the inspectors did not identify any instance when the breach of integrity actually exceeded the limit. Therefore, this event was not subject to enforcement action. The LER will remain open pending the inspectors' review of corrective actions.

M8.2 (Closed) LER 50-282/98013 (1-98-13): Scaffold Installation Interfered with Operability of Steam Exclusion Check Damper. This LER discussed an event, identified by the licensee, in which steam exclusion check damper CD-36036 was found to be inoperable because scaffolding interfered with the movement of its swing arm.

The performance of testing in accordance with SP 1117, "Steam Exclusion Check Damper Monthly Test," confirmed the proper operation of check dampers that were required to isolate safeguards equipment areas on the 695' level of the auxiliary building in the event of a high energy line break on the 715' level of the auxiliary building. A brief time-line of the events leading to CD-36036 inoperability was as follows:

- scaffolding was erected, on September 3, 1998, to allow operators to inspect CD-36035 and CD-36036;

- testing in accordance with SP 1117 was completed successfully on September 21, 1998;

- on September 21, 1998, the scaffolding was modified to allow for better access to the upper damper inspection port; and

- on October 11, 1998, testing in accordance with SP 1117 was conducted again, during which the licensee discovered that the scaffolding modification interfered with the movement of the CD-36036 swing arm, preventing the check damper from fully moving to its closed safeguards position; and

- once notified of the interference, the shift supervisor directed that the scaffolding modification be removed; testing was then successfully reperformed.

On October 12, 1998, as part of the corrective actions for this problem, the construction superintendent stopped all construction work and reviewed the event with all of the carpenters. Additional corrective actions included initiating NCR 19982493 to address the operability of CD-36036, issuing Corrective Action Request 19982507 to initiate an Error Reduction Task Force to investigate the human performance issues involving the placement of scaffolding around vital plant equipment, ensuring all scaffolding in the auxiliary building and turbine building was inspected by operations and carpenters for similar errors, revising Form 1198, "D80 Scaffolding Checklist," to direct the reperformance of the checklist after changes were made to existing scaffolding, and conducting training for carpenters, supervisors, and riggers on the revisions to Form 1198 and scaffold control procedures.

Technical Specification 3.4.C.1.a required that if one of the two redundant steam exclusion dampers is inoperable in excess of 24 hours, then one of the two dampers be closed. Contrary to this, check damper CD-36036 was inoperable from September 21, 1998, until October 11, 1998, with both the inoperable damper and the redundant operable damper in the open position. However, the safety significance of the event was low because the redundant damper was operable during the entire time that CD-36036 was blocked. 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 (50-282/98020-01(DRP); 50-306/98020-01(DRP)).

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Control Room Ventilation Background Noise Reduction

a. Inspection Scope (IP 92903)

The inspectors reviewed licensee efforts to reduce the background noise produced in the control room during control room special ventilation system operation.

b. Observations and Findings

The issue of excessive control room background noise during control room special ventilation operation was first identified in Inspection Report 50-282/96004(DRP); 50-306/96004(DRP), and later discussed in Inspection Report 50-282/96006(DRP); 50-306/96006(DRP). The issue of concern to the inspectors was that, with both trains of control room special ventilation running, the control room noise level was above the NUREG-0700 guideline of 65 decibels (dB) and that the noise level could hamper operator response to an actual event.

The inspectors reviewed Design Change 97ZN01 and followed the implementation of Phase 1 (Air Diffusers and Run Out [branch] Ducts) of the change. Phase 1 consisted of:

- removal of the 36 existing control room air diffusers and run-out ducts;
- enlarging the run-out duct openings in the main control room duct;
- installation of new low noise air diffusers and larger diameter ducts;
- installation of 12 additional run-out ducts and diffusers;
- installation of volume dampers in the new run-out ducts;
- balancing the system after diffuser and duct installation; and
- performance of a background noise survey.

The size of the ducts and the types of diffuser used were dependent on the location in the control room. Once begun, the equipment installation portion of the first phase was completed in a timely manner with little impact on the control room operators.

Following the installation of the new run-out ducts and diffusers, airflows were measured at each diffuser and adjusted to the required design flowrates. This adjustment was performed individually with just train A or train B of the control room special ventilation system operating and then with both trains operating simultaneously. After the system flow was balanced, sound (pressure) levels were measured at 11 locations in the control room during single train and dual train operation. The measurements were compared to the results of a similar test performed in 1996 and indicated, on average, an approximate 3.4 dB decrease for single train operation and an approximate 11.3 dB decrease for dual train operation. The inspectors noted that all of the sound level measurements obtained in the most recent test were below 65 dB. The system engineer informed the inspectors that the remaining three phases discussed in the design change would not be implemented at this time because of the success of the first phase.

c. Conclusions

Once the control room noise reduction design change received appropriate resources for implementation, the first phase of the project was successfully completed in a timely manner. The increase in number and size of the branch ducts, in conjunction with the installation of low noise air diffusers, effectively reduced the background noise in the control room during all modes of control room ventilation operation.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Inspection Followup Item 50-282/96004-01(DRP): Concern With Excessive Noise in the Control Room. This issue was previously discussed in Inspection Report 50-282/96004(DRP); 50-306/96004(DRP) and Inspection Report 50-282/96006(DRP); 50-306/96006(DRP). The licensee's corrective actions are discussed above in detail in Section E2.1 of this report.

E8.2 (Open) LER 50-282/98018; 50-306/98018 (1-98-18): Surveillance Testing of Boric Acid Storage Tank Level Logic Places Plant in Condition Where Single Failure Could Cause Inability to Inject Concentrated Boric Acid Immediately Following the Beginning of an Event Requiring Such Injection. While reviewing NRC Information Notice 97-81, "Deficiencies in Failure Modes and Effects Analysis for Instrumentation and Control Systems," dated November 24, 1997, the licensee identified a condition potentially outside of the plant design basis. On November 17, 1998, a corresponding event notification was made in accordance with 10 CFR 50.72. The licensee identified that when boric acid storage tank (BAST) level channels are placed in the trip condition during required monthly surveillance testing, a single failure of another channel could cause premature transfer of the safety injection pump suctions to the refueling water storage tanks. This would bypass the injection of highly borated water required to mitigate the effects of a steam line break accident.

For the short term, the licensee quarantined all applicable BAST surveillance procedures. The procedures were revised to physically realign the standby and in-service BAST tanks for each unit each month. As a permanent corrective action, an expedited TS amendment request was submitted to the NRC on November 25, 1998, to allow limited inoperability of BAST level and transfer logic channels during surveillance testing and maintenance of the associated components. The LER concerning the BASTs was due to be issued on December 17, 1998, and will be reviewed by the inspectors.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls (IP 71750)

R1.1 Radiological Controls During Unit 2 Reactor Vessel Head and Upper Internals Removal

The inspectors observed the radiological precautions and controls associated with removing the reactor vessel head and upper internals during the Unit 2 cycle 19 refueling outage. The pre-job briefings for the evolutions were complete and included a detailed review of expected dose rates, radiological controls, job times, and dose minimization practices. During both evolutions, health physics personnel continuously monitored dose rates and frequently informed personnel of their exposures. Inspectors and nonessential personnel were kept in low dose areas to minimize the overall dose associated with the evolutions. During movement of the reactor vessel head to the storage stand, health physics personnel ensured exposure to the underside of the head was avoided. Airborne radioactivity levels were monitored during both evolutions and the upper internals wetted periodically to prevent them from drying out and releasing radioactive material to the air.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on December 3, 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
J. Maki, Outage Manager
D. Schuelke, General Superintendent Radiation Protection and Chemistry
T. Silverberg, General Superintendent Plant Operations
M. Sleigh, Superintendent Security

INSPECTION PROCEDURES USED

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

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/98020-01(DRP) 50-306/98020-01(DRP)	NCV	Steam Exclusion Check Damper CD-36036 was Inoperable, in Excess of Technical Specification Time Limitations, Without Required Action Being Taken
50-306/98004 (2-98-04)	LER	Shield Building Integrity
50-282/98018 (1-98-18)	LER	Surveillance Testing of Boric Acid Storage Tank Level Logic Places Plant in Condition Where Single Failure Could Cause Inability to Inject Concentrated Boric Acid Immediately Following the Beginning of Event Requiring Such Injection

Closed

50-282/98020-01(DRP) 50-306/98020-01(DRP)	NCV	Steam Exclusion Check Damper CD-36036 was Inoperable, in Excess of Technical Specification Time Limitations, Without Required Action Being Taken
50-282/96004(DRP)-01 50-306/96004(DRP)-01	IFI	Concern With Excessive Noise in the Control Room
50-282/98016 (1-98-16)	LER	Negative Flux Rate Reactor Trip Upon Control Rod Insertion Following Failure of Control Rod Drive Cable
50-282/98008 (1-98-08)	LER	Reactor Trip Initiated by a Negative Flux Upon Control Rod Insertion Following Failure of Control Rod Drive Cable

50-282/98013 (1-98-13)	LER	Scaffold Installation Interfered with Operability of Steam Exclusion Check Damper

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
AWI	Administrative Work Instruction
BAST	Boric Acid Storage Tank
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
CV	Control Valve
dB	Decibels
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
°F	Degrees Fahrenheit
gpm	Gallons per Minute
IFI	Inspection Follow up Item
IP	Inspection Procedure
kV	kiloVolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MSDS	Material Safety Data Sheet
NCR	Nonconformance Report
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PM	Preventive Maintenance
RCS	Reactor Coolant System
RO	Reactor Operator
RPI	Rod Position Indication
SAC	Safety Audit Committee
SI	Safety Injection
SP	Surveillance Procedure
SRO	Senior Reactor Operator
TP	Test Procedure
TS	Technical Specification
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order