U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-282; 50-306
License Nos:	DPR-42; DPR-60
Report No:	50-282/98005(DRP); 50-306/98005(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	February 25 through March 28, 1998
Inspectors:	S. Ray, Senior Resident Inspector P. Krohn, Resident Inspector S. Thomas, Resident Inspector
Approved by:	J. W. McCormick-Barger, Chief Reactor Projects Branch 7

EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Unit 1 and Unit 2
NRC Inspection Report No. 50-282/98005(DRP); 50-306/93005(DRP)

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

Operations

- Most of the operations activities observed were accomplished well. In particular, two evolutions involving somewhat unusual reactivity manipulations, undertaken to determine the cause of a recurring noise in the Unit 1 reactor, were conducted carefully and conservatively. (Section O1.1)

- One crew of operators failed to use readily available alternate instrumentation to help determine the cause of an unusual source range nuclear instrument indication. (Section O1.1)

- In one case, an operator hung an isolation hold card on the wrong electrical breaker. The error was discovered by the electricians before starting work on the system. (Section O1.1)

- The Unit 2 startup and return to full power operation was conducted well with no discrepancies noted by the inspectors. The Unit 2 shift supervisor held timely and adequate pre-job briefings during the Unit 2 power ascension. Operators correctly followed procedures with a good questioning attitude. When discrepancies were found, procedure change requests were submitted. (Section O1.2)

- The spent fuel pool cooling system was found to be in good material condition with no discrepancies noted. For the areas examined, the as-built configuration of the spent fuel pool cooling system met the design basis requirements cited in the Updated Safety Analysis Report. (Section O2.1)

- Safety Audit Committee members engaged in an open, introspective discussion concerning the roles and responsibilities of the committee and its members. Emphasis was placed on methods to increase member's contact time with plant personnel to help them understand performance trends. (Section O7.1)

Maintenance

- Most of the 16 maintenance and surveillance test activities observed were performed well with few discrepancies noted. Proper operator self-checking techniques were observed during operability testing of the 12 diesel-driven cooling water pump and a good attitude towards continuous improvement was noted during this testing evolution. Procedures were cafefully reviewed and changes were made as appropriate, except for one case in which engineers misinterpreted the administrative requirements and failed to properly revise a work order when they determined that a change was needed. (Section M1.1)

- During annual maintenance on the 12 diesel-driven cooling water pump, a small opening was left uncovered in a piping system, indicating the need for increased attention-to-detail concerning foreign material exclusion controls. (Section M1.1)

- Engineering personnel failed to attach the appropriate temporary memorandum to a surveillance procedure affecting the 22 turbine-driven auxiliary feedwater pump and then did not cancel the same temporary memorandum attached to the applicable operating procedure in a timely manner when it was no longer needed. Since the temporary memorandum was not attached to the surveillance test, operations personnel were not aware of the temporary memorandum when the surveillance test was performed, and they would not have carried out its instructions. Had the pump's discharge check valve not already been repaired, damage to the suction pressure gauge and switch could have occurred. These concerns indicate a weakness in the administration of the temporary memorandum program. (Section M1.2)

- An inadequate preventive maintenance procedure resulted in a motor overload relay heater being set at a value that would not allow long-term operation of the motor. The subsequent post-maintenance test run was too short for the inappropriate value to be detected. (Section M3.1)

Engineering

- System engineering support for all operations and maintenance activities observed was excellent. System engineers closely monitored the status of their systems during the Unit 2 startup and power ascension. They consistently issued work orders promptly after equipment issues were identified, and were actively involved in or closely followed all troubleshooting and repair activities. (Section E2.1)

Report Details

Summary of Plant Status

Unit 1 operated at or near full power for the entire inspection period except for a brief power reduction for turbine valve testing. Unit 2 began the inspection period in cold shutdown, but was started up on March 4, 1998, and operated at or near full power for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (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

- At midnight on February 25, 1998, the Unit 2 control room operators noted that source range nuclear instrument 2N31 indication suddenly changed from 900 to 450 counts per second and 2N32 indication from 60 to 45 counts per second, simultaneously. After 15 minutes, both source range nuclear instrument channels returned to the previous values. No cause for the step change was identified by either the Unit 2 control room night shift or the oncoming day shift crews. When the inspectors became aware of the source range nuclear instrument anomaly, they asked the day shift supervisor if the Unit 2 event monitoring nuclear instruments, 2N51 and 2N52, had been checked to provide independent verification of source range power levels. The day shift supervisor stated that they had not thought about checking this alternate, independent indication of source range power level. The licensee later determined that the night shift crew had checked the event monitoring instrumentation but had apparently not passed on that information to the day shift crew.

  The Unit 2 reactor operator subsequently retrieved 2N51 and 2N52 source range neutron power levels from archived data on the plant computer system. When all source range indications were compared, the archived data showed that only 2N31 had actually experienced an unexplained step decrease. Normal instrument variations had occurred on 2N32 while 2N51 and 2N52 remained unchanged. As a precautionary measure, the licensee performed calibration checks on both source range nuclear instruments. Both instruments were found to be in proper calibration.

- On March 3, 1998, licensee electricians discovered that an operator had hung an isolation card on the wrong 125-volt direct current circuit breaker while performing an isolation for Work Order (WO) 9713200 for preventive maintenance on the 122 spent fuel pool special and inservice purge fan. The hold card for Breaker 14-9 was mistakenly hung on Breaker 14-7. The error resulted in securing power to the 122 auxiliary building special ventilation and the 12 shield building special ventilation filter pack fire protection deluge valves. There were no independent operator verifications required for hanging the hold card on Breaker 14-9, but the electricians performing the job conducted a hold card verification before beginning the work. When the operators became aware of the mistake, a hold card was immediately hung on Breaker 14-9 and the hold card on Breaker 14-7 was left in place until the system engineer could evaluate the effects of restoring power to the fire protection deluge valves. Operators were concerned that restoring power to the deluge valves might have caused them to actuate.

  The licensee reviewed the mistake and determined that no Technical Specification (TS) limiting conditions for operations had been entered. The hold card error was of minor safety significance since the 122 auxiliary building special ventilation and the 12 shield building special ventilation systems would still have performed their design safety functions. However, they would not have had automatic water deluge capability if a fire occurred in one of the charcoal filter beds. Breaker 14-9 was subsequently restored to its normal configuration on March 4, 1998. The licensee initiated an Error Reduction Task Force review of the event.

  Technical Specification 6.5 required, in part, that detailed written procedures be prepared and followed for preventive or corrective maintenance of plant equipment that could have an effect on nuclear safety. The instructions associated with WO 9713200 were not followed in that an isolation card was hung on an incorrect breaker. Tagging errors have been infrequent considering the large number of hold cards that were used in an operating cycle, so this error was considered an isolated instance, not evident of a programmatic weakness. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy (50-282/98005-01(DRP); 50-306/98005-01(DRP)).

- On March 12, 1998, the inspectors observed the pre-job briefing and activities associated with Unit 1 WO 9801541, "Dilute Control Bank D Rods to 180 Steps, While Holding Power." The purpose of the evolution was to examine impact sounds heard on the digital metal impact monitoring system (DMIMS) when control rods were inserted. The licensee had previously noted noises on DMIMS which seemed to be associated with control rod movement. During the performance of the evolution, Control Bank D rod insertion was offset by reactor coolant system (RCS) boron dilution, keeping reactor power essentially constant. Rod insertion was stopped at 196 steps, due to core power distribution concerns. Control bank D rods were then withdrawn to 218 steps while the RCS was borated and the rod control system was placed back in automatic operation. No change in the impact sounds heard on the DMIMS was noted.

The inspectors noted that the pre-job briefing was thorough, with slow, conservative reactivity changes and reactor safety being emphasized. The licensee's Nuclear Analysis Department provided information on expected parameter changes, which were taken from a computer model of the evolution. During the evolution, the inspectors observed good communication, conservative decision making, proper supervisory oversight, and positive control of the reactor plant. The inspectors also noted that the shift supervisor ensured that no other maintenance or testing was performed at the same time so that the reactor operator remained focused on monitoring the reactor plant during the reactivity changes required by the WO.

- The inspectors observed the pre-job briefing, the downpower transient to less than approximately 260 megawatts, and the surveillance test controlled by Surveillance Procedure (SP) 1054, "Turbine Stop, Governor and Intercept Valve Test," Revision 18. Surveillance SP 1054 demonstrated the operability of the turbine stop, governor, reheat stop, and intercept valves.

  During the initial portion of the downpower transient, to approximately 90 percent reactor power, the licensee performed additional monitoring, using the DMIMS, to try to determine the cause of a recurring noise in the Unit 1 reactor. In an attempt to eliminate control rods as a cause of the noise, the power reduction to 90 percent reactor power was performed using boron only and leaving Control Bank D rods at approximately 218 steps. The licensee noted that at 92.5 percent reactor power the noise went away.

  The inspectors noted that the pre-job briefing was thorough. The reactor power decrease was performed in a slow and controlled manner. Additional reactivity control guidance was provided to the control room operators for the initial decrease in power to approximately 90 percent through Temporary Memorandum (TMA) 1998-0011, "Reactivity Guidance for Unit 1 Turbine Valve Test," dated March 4, 1998. The inspectors observed that the surveillance test was completed in a safe manner, with three-way communication, proper supervisory oversight, procedure compliance, careful plant control, and good personnel coordination exercised throughout the evolution.

  The noise heard on the DMIMS returned shortly after the reactor was returned to full power and the cause had still not been positively identified at the end of the inspection period.

c. Conclusions

Most of the operations activities observed were accomplished well. Two evolutions involving somewhat unusual reactivity manipulations were conducted carefully and conservatively. However, the inspectors identified a situation where readily available alternate instrumentation was not used to help determine the cause of an unusual instrument indication and licensee personnel identified an isolation hold card hung on the wrong electrical breaker.

O1.2 Unit 2 Startup and Return to 100 Percent Power Operation

a. Inspection Scope (71707)

The inspectors observed Unit 2 startup and return to 100 percent power operation on March 4 and 5, 1998. Unit 2 had previously been shut down on January 24, 1998, following identification of a leak from a partial length control rod drive mechanism, as discussed in Inspection Report No. 50-282/98003(DRP); 50-306/98005(DRP), Section O1.3. The inspectors reviewed the following documents as part of this inspection:

- SP 2037, "Turbine Overspeed Trip Test," Revision 11;
- Operating Procedure 2C1.2, "Unit 2 Startup Procedure," Revision 18;
- Operating Procedure 2C1.3, "Unit 2 Shutdown," Revision 40;
- Operating Procedure 2C1.4, "Unit 2 Power Operation," Revision 15; and
- TMA 1998-0037, dated March 3, 1998.

b. Observations and Findings

During the approach to criticality, excellent control of the plant was observed. Operators, supervisors, and the nuclear engineer closely monitored all indications and independently tracked neutron multiplication. All alarms were properly acknowledged and announced to the crew. Criticality occurred at the predicted point and was properly recognized and recorded. When the reactor reached the point-of-adding-heat, the inspectors noted that the lead reactor operator assigned a dedicated steam system operator and gave him an excellent briefing on the plant status.

An operations shift turnover occurred during the startup. Reactor power was stabilized at six percent and no evolutions were conducted during the turnover period. The on-coming and off-going shift supervisors, lead reactor operators, and reactor operators all performed thorough walkdowns of control board panels, discussed upcoming surveillance tests, and reviewed steps that had been completed in Procedure 2C1.2. At one point, the shift supervisor and reactor operator had completed their turnovers but the lead reactor operator turnover was still in progress. The reactor operator notified the shift supervisor that he was going to check radiation monitors in the back of the control room and perform annunciator tests. The shift supervisor correctly realized that this would have taken the reactor operator away from the nuclear instrument, reactor coolant system, and steam generator control board panels that he had been monitoring while the lead reactor operator was distracted with turnover completion. The shift supervisor instructed the reactor operator to continue to monitor his control board panels until the lead reactor operator had completed his turnover.

Detailed briefings were conducted by the new crew before each major step in the startup. The shift supervisor conducted one briefing to discuss the continuation of power ascension. The briefing was thorough and complete and included discussions regarding formal communications, annunciator response, reactivity management, use of diverse plant indications, hold points, and relevant simulator experience. Another briefing, for SP 2037, was held prior to performing turbine overspeed trip testing. The briefing included emphasis on communications, operator roles, and actions for unexpected system responses. A briefing was also held prior to performing the 345 kilovolt substation manipulations and synchronizing the Unit 2 generator with the electrical grid.

Formal, three-way communications were used throughout the startup. An example occurred when an electrical substation operator's repeat back of a control room order was confusing. Both the lead reactor operator and the shift supervisor questioned the substation operator's understanding of the order he had just received. The order was repeated and clarified so that no doubt was left concerning the next operation.

The inspectors also noted a good awareness of procedural adherence requirements by the control room operators and a willingness to submit procedure deviations and change requests for minor discrepancies noted in Procedure 2C1.2. During overspeed protection controller testing prescribed in Procedure 2C1.2, Step U.6, the lead reactor operator noted that, although the turbine intercept valves closed rapidly, the same intercept valves took approximately 10 to 12 seconds to reopen. Step U.6 stated, "Observe intercept valves reopen rapidly." The word "rapidly" was questioned and a permanent procedure change request was submitted to remove the word from Step U.6.

On an earlier occasion a pressurizer level alarm was received while Unit 2 was in hot shutdown. The lead reactor operator properly consulted the alarm response procedure and an instrument and controls supervisor was called to investigate the reason for the alarm. Investigation revealed that the Unit 2 shutdown Procedure 2C1.3, Step 5.2.3.D, required the placement of the pressurizer level controller in manual and the adjustment of the output to 30 percent pressurizer level in preparation for cooling down from hot shutdown to cold shutdown. However, the complimentary startup Procedures 2C1.2 and 2C1.4 did not include any procedural steps for returning the pressurizer level controller to automatic. The licensee identified this discrepancy and submitted a procedure change request to include pressurizer level controller instructions in plant startup procedures.

c. Conclusions

The Unit 2 startup and return to full power operation was conducted well with no discrepancies noted by the inspectors. The Unit 2 shift supervisor held timely and adequate pre-job briefings during Unit 2 power ascension. Operators correctly followed procedures with a good questioning attitude. When discrepancies were found, procedure change requests were submitted.

O2 Operational Status of Facilities and Equipment

O2.1 Spent Fuel Pool (SFP) Cooling System Walkdown

a. Inspection Scope (62707, 71707)

The inspectors performed a walkdown of the SFP cooling system, checking material condition and verifying that design basis requirements were met in the as-built system. The inspectors reviewed the following documents as part of the inspection:

- USAR, Section 10.2.2, "Spent Fuel Pool Cooling System," Revision 14;

- SP 1776, "SFP Weir Gate Seals Annual Checkout," Revision 3;

- Drawing NF 39296-1, "Spent Fuel Pool Cleanup System," Revision L/M;

- Drawing NF 39296-2, "Spent Fuel Pool Cleanup System," Revision P;

- Drawing NF 40727-1, "Interlock Logic Diagram Spent Fuel Pool Cooling/Refueling Water Cleanup Units 1 & 2," Revision J;

- Drawing X-HIAW-1-29, "Flow Diagram Spent Fuel Cooling System Units 1 & 2," Revision X; and

- Drawing X-HIAW-1-703, "Prairie Island Nuclear Generating Plant Line List Spent Fuel Pool Cooling System," Westinghouse Electric Corporation Drawing 206C928, Sheet 4.

b. Observations and Findings

During the walkdown, the inspectors examined the material condition of the SFP heat exchangers, pumps, strainers, filters, skimmers, valves, and piping. All components were found to be in good material condition. The inspectors verified that the piping was arranged so that failure of any pipeline would not drain the SFP below the top of the stored spent fuel elements. The inspectors checked that SFP instrumentation was adequate to measure the effects of assumed accident conditions and the resultant maximum pool water temperatures. Inflatable spent fuel pool gate seal equipment was also located and examined to ensure proper staging if needed. Finally, the length of the flexible skimmer suction hoses were examined to ensure that even if the skimmers were to sink in the SFP, water level would still remain above the top of the stored spent fuel elements.

c. Conclusions

The SFP cooling system was found to be in good material condition with no discrepancies noted. For the areas examined, the as-built configuration of the SFP cooling system met the design basis requirements cited in the USAR.

O7 Quality Assurance in Operations

O7.1 Safety Audit Committee (SAC) Meeting Summary

The licensee SAC held their semi-annual meeting on March 11, 1998. The inspectors attended and observed portions of the meeting. Members engaged in an open, introspective discussion concerning the roles and responsibilities of the SAC and its members. Emphasis was placed on methods to increase SAC member's contact time with plant personnel to help them understand performance trends.

The general superintendent plant operations presented plans and goals for operations department improvement initiatives. Six areas for emphasis in the coming year were presented; communications, pre-job briefings, control room decorum, procedural adherence, reactivity control, and self-checking.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Surveillance Testing and Maintenance Observations

a. Inspection Scope (61726, 62707)

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

- SP 1054 Turbine Valve, Governor and Intercept Valve Test, Revision 18;
- SP 1094 Bus 15 Load Sequencer Test, Revision 11;
- SP 1106A 12 Diesel Cooling Water Pump Test, Revision 53;
- SP 1116 Monthly Power Distribution Map Unit 1, Revision 25;
- SP 1253 Alternating In-Service Control Room Chillers, Revision 7;
- SP 1274 Core Exit Thermocouple Operability Test Unit 1, Revision 7;
- SP 2037 Turbine Overspeed Trip Test, Revision 11;
- SP 2073 Unit 2 Shield Building Ventilation System Functional Test, Revision 36;
- SP 2103 22 Turbine-Driven Auxiliary Feedwater Pump Once Every Refueling Shutdown, Revision 29;
- WO 9713243 PM [Preventive Maintenance] 3002-3-12, 12 Diesel Cooling Water Pump Annual Electrical PM, Revision 3;
- WO 9800219 PM 3002-2-12, 12 Diesel Cooling Water Pump Annual Inspection, Revision 16;
- WO 9800293 Repair Control Room Outside Air Damper Train B;
- WO 9801034 Perform Diverse Scram System Rod Drop Test at Hot Shutdown;
- WO 9801541 Dilute Control Bank D Rods to 180 Steps, While Holding Power;

- WO 9803330 2AC Urgent Alarm; and

- WO 9803463 Unit 0 Auxiliary Building Normal Ventilation, Remove Duct Work to Waste Gas Compressor Area for Flooding Scenario.

b. Observations and Findings

- The inspectors attended the pre-job briefing and observed the performance of diverse scram system rod drop testing at hot shutdown in accordance with WO 9801034. The briefing included discussions of reactor operator actions, major procedural steps, reasons to abort the test and open the reactor trip breakers, and the nuclear instrumentation indications to be observed during the test. The test procedure was properly followed. The reactor operator closely monitored rod bottom lights, rod position indicators, and nuclear instruments. The shift supervisor closely monitored all reactivity manipulations. While removing fuses in auxiliary power supply cabinet 21BD, the licensee noted a typographical error in the WO. The testing was stopped, the system engineer came to the control room from a local data acquisition station, and a procedure deviation was processed. The rod drop test was subsequently completed satisfactorily.

- The inspectors witnessed portions of the annual inspection of the 12 diesel-driven cooling water pump (DDCLP) in accordance with WO 9801034. The pump was a safety-related component that supplied water to the train A cooling water header. On March 17, 1998, the inspectors noticed that a 3/8-inch diameter compression fitting on the inlet side of the 12 DDCLP angle drive gear box bearing filter was open to the environment. Foreign materials could potentially have entered the angle drive gear box bearing water system through this opening. Several other work activities were being conducted in the immediate area, so the potential for foreign material introduction was present. The inspectors brought the discrepancy to the attention of a maintenance supervisor working in the area. The supervisor placed a foreign material exclusion cover over the opening. Since the opening was small and on the inlet side of the filter housing, it was unlikely that potentially damaging foreign material would have reached any angle drive bearings and caused damage.

  On March 19, 1998, the inspectors witnessed operability testing of the 12 DDCLP in accordance with Step 7.6 of PM 3002-2-12. The operability testing included setting and testing of diesel governor hunting controls, low and high speed stops, speed switching, and overspeed tripping. No discrepancies were noted. The inspectors also witnessed the satisfactory performance of SP 1106A. The inspectors verified that the 12 DDCLP pump performance met the requirements of the American Society of Mechanical Engineers Section XI inservice testing program.

  During the testing in accordance with SP 1106A, Step 7.6.B.3, the inspectors noticed that an operator began to incorrectly close Valve CL-39-2, the discharge valve on the 12 DDCLP, instead of Valve CL-39-1, the discharge valve on the 11 cooling water pump. Closing CL-39-2 with the 12 DDCLP running was undesirable since damage to the pump could occur. Just as the inspectors were about to point out the error, the operator properly used self-checking techniques and realized his own mistake. At that point the valve had only been closed about one turn (approximately 15 to 20 turns would have been required to fully close CL-39-2). The operator immediately reopened CL-39-2 and proceeded to close CL-39-1 in accordance with Step 7.6.B.3. The operator subsequently initiated an Employee Observation Report describing his mistake to the licensee's Safety Assessment Department.

- The inspectors observed Bus 15 load sequencer testing in accordance with SP 1094. The surveillance tested the software and hardware operability of the Bus 15 load sequencer up to and including the output relays. The inspectors noted that the electrician performing the test properly identified all controls that were to be operated and all indications to be observed, prior to performing the applicable step in the procedure. Adequate electrical safety measures were utilized when entering energized electrical cabinets.

- On March 17, 1998, a rod control urgent failure alarm occurred on the Unit 2 annunciator panel. Operators performed the actions required by the appropriate alarm response procedure, which included placing the rod control system in manual. A preliminary investigation by the licensee revealed that the alarm was caused by a logic failure in the 2AC rod control power cabinet. Although the logic failure did not cause any control rod misalignment, it did render nine control rods (two in Shutdown Bank A, four in Control Bank A, and three in Control Bank C) inoperable, but trippable. Although the licensee considered the controlling rods, Control Bank D, to be operable, the licensee chose to refrain from further rod motion until additional troubleshooting could be performed.

  The licensee performed troubleshooting using WO 9803330. The inspectors observed the work which included placing specified control rods on the hold bus; verifying voltages and currents associated with the affected rod groups; performing diagnostic tests on the 22AC Group C firing, phase control, and regulation cards; resetting the rod control system alarm reset switch; and investigating the alarm circuitry card. The troubleshooting did not reveal any abnormal conditions or faulty components which could have caused the rod control system urgent failure alarm, and the alarm cleared when the reset button was depressed.

  During the performance of the work specified in WO 9803330, the inspectors noted that the engineers supervising the work were moving on from Step 8.1 to Step 8.2 without completing all the actions of Step 8.1. Step 8.1 required the installation of test equipment that would monitor various voltages and currents in the 2AC power cabinet during the time when the rod control system alarm reset button was depressed. Just prior to the time an instrument and control technician was to reset the alarm, the inspectors questioned why test equipment had not been installed at stationary firing card zero current order (Test Point 12 on Terminal Strip G1) and stationary firing card reduced current order (Test Point 13 on Terminal Strip G1). The system engineer said that the reason test equipment had not been installed at those locations was that the test equipment did not have any input channels left available.

The system engineer then initiated a change to the master WO procedure to delete those two test points, and the engineers with Step 8.2. The inspectors noted that the change to Step 8.1 was made after the step had been completed, contrary to the instructions of 5AWi (Administrative Work Instruction) 3.2.8, "Work Order Package Change Process," Revision 2, Step 6.2.3.a, which required that, "Changes to work packages SHALL be prepared, reviewed, and approved prior to implementation." Also the inspectors noted that the control room operators were not informed of the change even though Special Consideration 2 of WO 9800330 stated, "Operations SHALL be notified prior to any changes made." However, the inspectors noted that Step 6.2.3 of 5AWI 3.2.8 did not require notification of the shift supervisor unless the change affected plant operations.

The inspectors discussed their observations with the system engineers' supervisors who said that the engineers had discussed deleting two of the test points from being monitored and decided that the work order change process did not apply to that change. The inspectors reviewed both 5AWI 3.2.8 and 5AWI 1.5.8, "Procedure Adherence," Revision 0, and determined that the requirements of 5AWI 3.2.8 did apply. The inspectors agreed that this had not been an intentional violation of procedures because the engineers had properly used 5AWI 3.2.8 for several other more substantive changes to the WO. Since the change in question only affected the attachment of test equipment and not the actual performance of work on the system, the engineers misinterpretation of the requirements was not a significant error.

The rod control system was not a safety-related system and WO 9800330 was not considered a maintenance procedure for which the quality assurance program or TS requirements applied. However, 5AWI 3.2.8 for changing work orders applied to all types of work orders and was a procedure for which the adherence requirements of the quality assurance program applied.

Criterion V, "Instructions, Procedures, and Drawings," of Appendix B of 10 CFR Part 50 required, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings. The change made to WO 98003330 was not performed in accordance with the administrative requirements of 5AWI 3.2.8. However, the violation only affected test equipment and not actual plant equipment. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy (50-306/98005-02(DRP)).

c. Conclusions

Most of the 16 maintenance and surveillance test activities observed were performed well with few discrepancies noted. Proper operator self-checking techniques were observed during operability testing of the 12 DDCLP and a good attitude towards continuous improvement was noted during this testing evolution.

Procedures were carefully reviewed and changes were made as appropriate except for one case in which engineers misinterpreted the administrative requirements and failed to properly revise a work order. In addition, annual maintenance performed on the 12 DDCLP revealed the need for increased attention-to-detail concerning foreign material exclusion controls.

M1.2 Temporary Memorandum (TMA) Use During Performance of the 22 Turbine-Driven Auxiliary Feedwater Pump (TDAFWP) Surveillance Test

a. Inspection Scope (61726, 62707)

On March 4, 1998, during the Unit 2 return to 100 percent power operation, the inspectors witnessed the pre-job briefing and testing of the 22 TDAFWP. The following documents were reviewed as part of the inspection:

- SP 2103, "22 Turbine Driven Auxiliary Feedwater Pump Once Every Refueling Shutdown," Revision 29;
- TMA 1998-0025, "SP 2103, 22 Turbine Driven Auxiliary Feedwater Pump Once Every Refueling Shutdown," Revision 29, dated January 30, 1998;
- TMA 1997-0214, "2C28.1, Auxiliary Feedwater System - Unit 2, Revision 2," dated December 6, 1997; and
- WO 9800532, "Disassemble, Inspect, and Repair Valve AF-15-12."

b. Observations and Findings

The pre-job briefing for SP 2103 was thorough. Communications, operator actions and responsibilities, special considerations, prerequisites, initial conditions, and TMA 1998-0025 were discussed. The surveillance test was performed at approximately 25 percent reactor power with one main feed pump running and steam generator water level being controlled automatically with the main feedwater regulating valves.

Problems with pressure transients occurring in the suction line of the 22 TDAFWP were previously discussed in Inspection Report No. 50-282/97018(DRP); 50-306/97018(DRP), Section M1.1. As a result of these transients, the licensee issued TMA 1997-0214 which modified the 22 TDAFWP operating procedure to isolate the suction pressure gauge and low suction pressure trip sensing line just prior to pump shutdown and to return them to service immediately after the pump was secured. However, TMA 1997-0214 only applied to the normal system operating Procedure 2C28.1, and not to refueling surveillance SP 2103, which also contained instructions for running the 22 TDAFWP.

During the Unit 2 outage at the beginning of the inspection period, the 22 TDAFWP discharge check valve, AF-15-12, was repaired using WO 9800532. Post-maintenance testing was performed on March 2, 1998, and showed that the pressure transients occurring in the suction line had been eliminated. Thus, TMA 1997-0214 was no longer necessary and could have been canceled on March 2.

During performance of SP 2103 on March 4, 1998, the inspectors noted that TMA 1997-0214 was still in effect and had not been discussed during the pre-job briefing for the surveillance test. The inspectors brought this to the attention of the system engineer observing SP 2103. The system engineer acknowledged that TMA 1997-0214 was still active and stated that since WO 9800532 had successfully repaired the 22 TDAFWP discharge check valve, TMA 1997-0214 could have been canceled. The system engineer returned to the control room, discussed TMA 1997-0214 with the Unit 2 shift supervisor, and canceled the temporary memorandum while SP 2103 was still in progress.

The inspectors interviewed the local operator monitoring the 22 TDAFWP in the auxiliary feedwater pump room and the control room operator leading SP 2103 after the surveillance test was complete. Both stated that they were unaware of the existence of TMA 1997-0214 and would have shut down the 22 TDAFWP without isolating the suction pressure gage and switch.

The inspectors noted two problems with temporary memorandum administration during performance of SP 2103.

- The equipment operating guidance to address concerns associated with suction pressure transients was applied to the normal operating procedure for the 22 TDAFWP, 2C28.1, through TMA 1997-0214, but not to the refueling surveillance, SP 2103. An engineering supervisor stated that the licensee had not expected to run the refueling surveillance anytime soon when the TMA was written.

- The system engineer did not cancel TMA 1997-0214 when repairs were satisfactorily completed on March 2, 1998.

Although no regulations or procedures were violated during the handling of the temporary memorandum, the concerns described above represent a weakness in administration of the temporary memorandum program.

c. Conclusions

Engineering personnel failed to attach the appropriate temporary memorandum to a surveillance procedure affecting the 22 TDAFWP and did not cancel the same temporary memorandum attached to the applicable operating procedure in a timely manner when the memorandum was no longer needed. Since the temporary memorandum was not attached to the surveillance test, operations personnel were not aware of the temporary memorandum when the surveillance test was performed and they would not have carried out its instructions. Had the pump's discharge check valve not already been repaired, damage to the suction pressure gauge and switch could have occurred. These concerns indicate a weakness in the administration of the temporary memorandum program.

M3 Maintenance Procedures and Documentation

M3.1 Inadequate Preventive Maintenance Procedure Setpoint

a. Inspection Scope (92700)

On February 27, 1998, the licensee informed the inspectors that it had inadvertently failed to meet a TS Limiting Condition for Operation associated with an emergency diesel generator (EDG). The inspectors reviewed the circumstances of the event.

b. Observations and Findings

The licensee reported this event in Licensee Event Report (LER) 1-98-04, "Engineered Safety Feature Equipment in Alternate Train Inoperable During Diesel Generator Monthly Surveillance Run," on March 27, 1998. The inspectors reviewed the LER and determined that it accurately described the event. On February 21, 1998, the licensee took the 121 (train A) control room ventilation system out-of-service for routine preventive maintenance including refurbishment of the electrical breaker for the air handler fan. The maintenance was completed and the system was declared operable following a brief post-maintenance operability run of the system on February 26, 1998.

Later on February 26, 1998, a routine monthly surveillance test of the D2 (train B) EDG was conducted. During the test, the EDG was considered inoperable. Technical Specification 3.7.B.1 required, in part, that all engineered safety features equipment associated with the operable (train A) diesel generator be operable. Later the same day, after the 121 control room ventilation air handler fan tripped, the licensee discovered that the system had been inoperable because the air handler fan breaker's thermal overload relay had been set too low during the earlier preventive maintenance activity. The low overload setting had not been discovered in the post-maintenance operability run because the overload was designed to trip based on a current/time relationship and the fan had not been run long enough to actuate it. The overload relay was replaced and set to the correct value on February 27, 1998.

As reported in the LER, the condition was a violation of TS 3.7.B.1. Operability requirements for the 121 control room ventilation system itself were not violated because the total time the system was inoperable was less than the seven-day allowance in TS 3.13.A.2. The licensee-identified event was only of minor safety significance because the redundant 122 control room ventilation system was continuously operable and the D2 EDG was continuously operable except during the brief period of testing.

The cause of the event was an inadequate procedure for calculating the thermal overload relay test currents, as described in the LER. The resultant overload settings were conservative from a motor protection standpoint but not optimum for the actual operating condition of the system. The corrective actions described in the LER were adequate and in progress. Although there have been other recent violations for inadequate procedures, the types of inadequacies in those citations were substantially different from this inadequate calculational procedure, so the event was considered non-repetitive. The licensee had instituted a comprehensive procedure improvement program in response to those earlier concerns. 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 (50-282/98005-03(DRP)). The LER associated with the event (50-282/98004) will remain open pending completion of the long-term corrective actions.

c. Conclusions

An inadequate preventive maintenance procedure resulted in a motor overload relay heater being set at a value that would not allow long-term operation of the motor. The subsequent post-maintenance test run was too short for the inappropriate value to be detected.

M8 Miscellaneous Maintenance Activities (92700, 92902)

M8.1 (Closed) Inspection Followup Item (IFI) 50-282/97005-04(DRP); 50-306/97005-04(DRP): Technical Specification Surveillance Interval Requirements. This issue was previously discussed in Inspection Report No. 50-282/97005(DRP); 50-306/97005(DRP), Section M7. It involved questions, first raised by licensee quality services personnel, regarding the interpretation of the allowed interval between surveillance tests. The NRC Office of Nuclear Reactor Regulation determined that the licensee's practice of using a "fixed" surveillance schedule, as described in the above mentioned report, and allowing plus or minus 25 percent adjustments to that schedule, was acceptable in accordance with TS 4.0.

M8.2 (Closed) Licensee Event Report 50-306/96004 (2-96-04): Failure to Perform SP 2244, Cycling of Unit 2 Containment Air Sample Valves. This event was previously discussed in Inspection Report No. 50-282/96016(DRP); 50-306/96016(DRP), Section M8.2. It involved a surveillance test that was missed because the wrong test procedure was inadvertently used. The inspectors verified the completion of the corrective actions discussed in the LER.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support of Operations and Maintenance Activities

a. Inspection Scope (37551)

The inspectors monitored the quality of engineering support for operations and maintenance activities during the inspection period.

b. Observations and Findings

The following were some examples of engineering support activities observed.

- On one occasion during the Unit 2 startup, when the generator exciter field breaker was closed, the bus duct cooling fans started but tripped after approximately two minutes. The system engineer had been observing control room operations and responded to the local bus duct cooler control panel. Electrical prints were examined and a control fuse was found blown. The control fuse was replaced and power ascension activities resumed.

- System engineers were very actively involved with the troubleshooting activities associated with the Unit 2 rod control urgent failure alarm. A comprehensive and well-thought-out troubleshooting plan was developed and carefully followed. The engineers incorporated vendor recommendations but did not limit the plan to only those suggestions. The engineers were present for all troubleshooting activities and kept the control room operators well informed of the plans and findings.

c. Conclusions

System engineering support for all operations and maintenance activities observed was excellent. System engineers closely monitored the status of their systems during the Unit 2 startup and power ascension. They consistently issued work orders promptly after equipment issues were identified, and were actively involved in or closely followed all troubleshooting and repair activities.

E2.2 Review of Updated Safety Analysis Report (USAR) Commitments (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 identified.

E8 Miscellaneous Engineering Issues (92700, 92903)

E8.1 (Closed) Inspection Followup Item 50-282/96006-02(DRP); 50-306/96006-02(DRP): Revisions or Enhancements Needed for Flood Procedures. This issue was previously discussed in Inspection Report No. 50-282/96006(DRP); 50-306/96006(DRP), Section O3.1. It involved various discrepancies in the licensee's abnormal procedures, SPs, TSs, and the USAR associated with flooding. The inspectors verified that Abnormal Procedure AB-4, "Flood," Revision 12, and SP 1293, "Flood Preparation - Flood Control Panel Inspection/Installation," Revision 5, contained revisions that resolved the inspectors' concerns. In addition, the inspectors noted that SP 1293 was being conducted annually each March, instead of June, as had been done for the previous few years. That allowed the licensee to verify that the flood protection features were ready for use shortly before the typical flood season.

Another concern discussed in Inspection Report No. 96006 was an error in TS 5.1 regarding the number of flood protection panels in the plant. That error will be corrected in a License Amendment for which the licensee first submitted a request on September 11, 1996. The request had since been revised several times and was awaiting NRC approval. In addition, in the referenced inspection report the inspectors noted that there was an error in USAR Figure 2.4-7 regarding flood protection panels. The inspectors verified that a drawing revision was in progress and that the discrepancy had been entered in the licensee's USAR Upgrade Project tracking system. Finally, the inspection report discussed the inspectors' concern that flood protection panels were not stenciled with the appropriate mark numbers per drawing NF-117033. The inspectors verified that the panels were now labeled.

E8.2 (Closed) LER 50-282/96013; 50-306/96013 (1-96-13): Cable Tray Separation Discrepancies, and

(Closed) Unresolved Item 50-282/96008-09(DRP); 50-306/96008-09(DRP): Cable Tray Installations Which Did Not Meet the Separation Criteria in the USAR.

This issue was previously discussed in Inspection Report Nos. 50-282/96008(DRP); 50-306/96008(DRP), Section E2.1, 50-282/96014(DRP); 50-306/96014(DRP), Section O2.1, and 50-282/97008(DRS); 50-306/97008(DRS), Section E8.4. In the later report, a violation (50-282/97008-13(DRS); 50-306/97008-13(DRS)) was issued for the failure to promptly identify and correct the separation discrepancies.

The licensee implemented an extensive project to identify all cable tray interactions that did not meet the criteria in the USAR. In all, 107 interactions needing remedial action were identified. The discrepancies included a mix of original construction problems and improper application of the USAR design specifications to later modifications. The licensee performed prompt operability assessments using a blanket safety evaluation and a blanket engineering calculation as each new interaction was identified. Operability determinations were based on evaluations of newer electrical separation standards, cable armor, circuit fault current analysis, and redundant circuit analysis. The licensee determined that each of the interactions was operable in the "as found" condition and each interaction was corrected to meet the USAR separation criteria by the installation of fire barriers (tray covers).

In addition to resolving the separation discrepancies, other corrective actions discussed in the LER were also completed. Additionally, licensee personnel identified several drawing errors and other miscellaneous discrepancies during the project which were either corrected or entered into a tracking data base.

The violation associated with the failure of the licensee to promptly identify and correct the separation discrepancies remains open pending a review of the corrective actions by NRC Division of Reactor Safety inspectors.

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 March 26, 1998. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Sorensen, Plant Manager
K. Albrecht, General Superintendent Engineering, Electrical/Instrumentation & Controls
T. Amundson, General Superintendent Engineering, Mechanical
J. Goldsmith, General Superintendent Engineering, Generation Services
J. Hill, Manager Quality Services
G. Lenertz, General Superintendent Plant Maintenance
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 57080:	Nondestructive Examination Procedure Ultrasonic
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
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

<u>Opened</u>

50-282/98005-01(DRP) 50-306/98005-01(DRP)	NCV	Failure to Follow Work Order Instructions by Hanging Isolation Card on the Wrong Breaker
50-306/98005-02(DRP)	NCV	Failure to Follow Administrative Requirements for a Change to a Work Order
50-282/98005-03(DRP)	NCV	Inadequate Procedure for Calculating Motor Thermal Overload Setting
50-282/98004 (1-98-04)	LER	Engineered Safety Feature Equipment in Alternate Train Inoperable During Diesel Generator Monthly Surveillance Run

<u>Closed</u>

50-282/97005-04(DRP) 50-306/97005-04(DRP)	IFI	Technical Specification Surveillance Interval Requirements
50-306/96004 (2-96-04)	LER	Failure to Perform SP 2244, Cycling of Unit 2 Containment Air Sample Valves
50-282/96006-02(DRP) 50-306/96006-02(DRP)	IFI	Revision or Enhancements Needed for Flood Procedures
50-282/96013 (1-96-13) 50-306/96013	LER	Cable Tray Separation Discrepancies
50-282/96008-09(DRP) 50-306/96008-09(DRP)	URI	Cable Tray Installations Which Did Not Meet the Separation Criteria in the USAR

<u>Discussed</u>

50-282/97008-13(DRS) 50-306/97008-13(DRS)	VIO	Design Control Violation Involving Untimely Corrective Action on Cable Tray Separation Issue

LIST OF ACRONYMS USED

AWI	Administrative Work Instruction
CFR	Code of Federal Regulations
DMIMS	Digital Metal Impact Monitoring System
DDCLP	Diesel-Driven Cooling Water Pump
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
IFI	Inspection Followup Item
IP	Inspection Procedure
LER	Licensee Event Report
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
PM	Preventive Maintenance
SAC	Safety Audit Committee
SFP	Spent Fuel Pool
SP	Surveillance Procedure
TDAFWP	Turbine-Driven Auxiliary Feedwater Pump
TMA	Temporary Memorandum
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order