U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-282/89017(DRP); 50-306/89017(DRP)

Docket Nos. 50-282; 50-306 License No. DPR-42; DPR-60

Licensee: Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

Facility Name: Prairie Island Nuclear Generating Plant

Inspection At: Prairie Island Site, Red Wing, MN

Inspection Conducted: April 16 through May 26, 1989

Inspectors: J. E. Hard

T. J. O'Connor

Approved By: B. Burgess, Chief
Reactor Projects Section 2A

6/20/89
Date

Inspection Summary

Inspection on April 16 through May 26, 1989 (Reports No. 50-282/89017(DRP); 50-306/89017(DRP))
Areas Inspected: Routine unannounced inspection by resident inspectors of previous inspection findings, plant operational safety, maintenance, surveillances, ESF systems, security, quality assurance (QA) programs and followup of LERs and Generic Letters.
Results: During this inspection period, Unit 1 operated continuously at 100% power, except for a power reduction associated with the cleaning of condenser tubes and addition of lubricating oil to the 11 and 12 reactor coolant pumps. Reactor coolant system radiochemistry continues to indicate the presence of a failed fuel rod. Activity levels continue to remain less than one percent of Technical Specification (TS) limits. On May 22, 1989, the 12 motor driven auxiliary feedwater (MDAFW) pump autostarted as a result of an electrical component failure in a non safety related system.

Unit 2 entered the inspection period in the final stages of a refueling outage. The reactor went critical at approximately 0230 hours on April 28, 1989, and the generator was placed on line at approximately 1640 hours on

April 29, 1989. Initial power operations were restricted to less than 100% due to hot channel factor limits associated with the refueled core. Accordingly, the high power range reactor trip was reduced from 108% to 105.4%. Testing of the new feedwater control verified correct installation. The feedwater control tests showed a greatly improved ability to handle and correct transients. On May 26, 1989, a Unit 2 reactor trip occurred as a result of a transient initiated by an electrical component failure in a non-safety-related system. It should be noted that this is the first reactor trip to occur at the facility since July 1987 and the first trip on Unit 2 since July of 1986.

Of the 7 areas inspected, 2 violations of NRC requirements were identified.

DETAILS

1. Persons Contacted

L. Eliason, General Manager, Nuclear Plants
#E. Watzl, Plant Manager
R. Lindsey, Assistant to the Plant Manager
D. Mendele, General Superintendent, Engineering and Radiation Protection
#M. Sellman, General Superintendent, Operations
G. Lenertz, General Superintendent. Maintenance
A. Smith, General Superintendent, Planning and Services
D. Schuelke, Superintendent, Radiation Protection
G. Miller, Superintendent, Operations Engineering
#K. Beadell, Superintendent, Technical Engineering
S. Schaefer, Superintendent, Nuclear Engineering
M. Klee, Superintendent, Quality Engineering
P. Kamman, Superintendent, Nuclear Operations QA
R. Conklin, Superintendent, Security and Services
D. Vincent, Project Manager, Nuclear Engineering and Construction
D. Musolf, Manager Nuclear Support Services
J. Goldsmith, Superintendent, Nuclear Technical Services
#A. Hunstad, Staff Engineer
T. Amundson, Superintendent Training
J. Leveille, Senior Nuclear Safety/Technical Services Engineer
A. Vukmir, Site Services Representative, Westinghouse Electric Corp.
R. A. Kerr, Manager, Control Systems Design Technology, Westinghouse

The inspectors interviewed other licensee employees, including members of the technical and engineering staffs, shift supervisors, reactor and auxiliary operators, QA personnel, shift technical advisors, and shift managers.

#Denotes those present at the exit interview of May 30, 1989.

2. Licensee Event Report Followup (93702)

(Open) 282/89004-LL: Openings in the Auxiliary Building Special Ventilation Zone (ABSVZ) Boundary Not Under Administrative Control

On April 20, 1989, operators performing a valve verification lineup for the integrated leakage rate test reported that air was blowing out of the two main steam line vent valves. Noting that these valves were not logged on the ABSVZ log, a walkdown of the main steam lines was conducted. This walkdown revealed that the disassembled main steam isolation valve (MSIV) RS-19-[illegible] also provided an opening in the ABSVZ boundary. (See Paragraph No. 3 for additional information.)

(Open) 282/89005-LL: Auto Start of the 12 Motor Driven (MD) Auxiliary Feedwater (AFW) Pump.

At approximately 0216 hours, on May 22, 1989, the 12 MDAFW pump experienced an auto start. The initiating event was the failure of a DC voltage sensor. Failure of the sensor caused an auto transfer to the backup source of DC control power. The transfer, a break before make, caused the momentary deenergization of a relay which allowed for the completion of the 12 MDAFW pump start circuitry.

(Open) 282/89006-LL: Autostart of 122 Control Room Cleanup Fan and Isolation of Outside Air Supply Dampers.

At approximately 0137 hours on May 26, 1989, the 122 control room cleanup fan autostarted and the outside air supply dampers isolated. The event occurred as a result of the process paper jamming on the 122 toxic gas monitor.

(Open) 306/89002-LL: Unit 2 Reactor Trip

At approximately 0605 hours on May 26, 1989, Unit 2 experienced a reactor trip. The reactor tripped on low-low steam generator (SG) level in the 22 SG. The initiating event was a capacitor failure on an amplifier card associated with the turbine speed feedback network. The capacitor's failure caused the 15 volt bus to short to ground which caused a loss of power to the electro-hydraulic controls. This loss of power caused the control valves to close which caused an increase in steam line pressure and a concurrent shrinking of the SG level.

3. Operational Safety Verification (71707, 93702, 71711, 82301)

The inspector observed control room operations, reviewed applicable logs, conducted discussions with control room operators and observed shift turnovers. The inspector verified operability of selected emergency systems, reviewed equipment control records, and verified the proper return to service of affected components, tours of the auxiliary building, turbine building and external areas of the plant were conducted to observe plant equipment conditions, including potential fire hazards, and to verify that maintenance work requests had been initiated for the equipment in need of maintenance.

Unit 1 operated continuously at 100% power, except for a power reduction associated with the cleaning of the condenser tubes and addition of lubricating oil to the 11 and 12 reactor coolant pumps. Reactor coolant system radiochemistry continues to indicate the presence of a failed fuel rod. Activity levels continue to remain less than one percent of TS limits. Unit 2 completed its refueling outage with the taking of the reactor critical at approximately 0230 hours on April 28, 1989, and placing the generator on-line at approximately 1640 hours on April 29, 1989. Initial power operations were restricted to less than 100% due to hot channel factor limits associated with the refueled core. Accordingly, the high power range reactor trip was reduced from 108% to 105.4%. The inspector monitored core physics testing. On May 12, 1989, the restricted power level was lifted, allowing 100% power operation and a resetting of the high power range reactor trip setpoint to 108%.

On April 20, 1989, operators performing a valve verification lineup for the integrated leakage rate test (ILRT) reported that air was blowing out of the two main steam line vent valves. Noting that these valves were not logged on the ABSVZ log, a walkdown of the main steam lines was conducted. This walkdown revealed that the disassembled main steam isolation valve (MSIV) RS-19-4 also provided an opening in the ABSVZ boundary. The opening was through the open vent valves and the MSIV through the main steam lines and out through the turbine control valves. The turbine control valves were disassembled for outage rebuilding.

An investigation by the licensee into the event indicated that it was not recognized by operations that the disassembly of the MSIV would result in an opening in the ABSVZ. Additionally, the surveillance procedure for the ILRT did not alert the shift supervisor to the possibility that opening the vents could result in an opening in the ABSVZ. It should be noted, however, that the work request which authorized the disassembly of MSIV RS-19-4 referenced in the Special Instruction Section 3.6.A.8 and also referenced a previous work request which created this same opening.

3.6.A.8 requires, in part, that during maintenance and testing activities, containment integrity is considered intact if the auxiliary building special vent zone (ABSVZ) boundary is opened intermittently, provided such openings are under direct administrative control and can be reduced to less than 10 square feet within 6 minutes following an accident.

Operations Procedure D54, Control of Openings in the Auxiliary Building Special Vent Zone Boundary, Rev. 3., requires that a log be kept in the control room which specifies the size and location of all openings in the ABSVZ. The log shall include the time and date openings are made and when they are closed.

From approximately 0800 hours on April 13, 1989, to 1402 hours on April 20, 1989, an opening in the ABSVZ was not under administrative control as required by D54 or Tech Spec 3.6.A.8 and is identified as Violation 50-306/89017-01(DRP).

On May 9, 1989, the resident inspectors participated in the Prairie Island emergency drill. The drill scenario and plant response was observed from the simulator's control room, the technical support center and the emergency response facility. The inspectors were satisfied with all activities conducted during the course of the drill, noting constructive critiques of the simulator's control room activities.

On May 10, 1989, the resident inspector noticed that the Superintendent of Security and Services' office was unlocked as were the file drawers containing safeguards information. The superintendent had briefly stepped out of his office. In conjunction with Region III staff, the superintendent was advised that, although he was in the immediate area, positive control over safeguards information is the practice accepted by the NRC.

On May 22, 1989, a plant equipment operator discovered the control power fuses for the 8H13 breaker were removed. 8H13, along with 8H14, ties Unit 2 into the offsite distribution grid. Any annunciators which may have alarmed would not have alarmed in the substation or main control room annunciator as a result of these fuses being removed. At the time of this discovery, 8H14 was undergoing maintenance and was disengaged, leaving 8H13 as the Unit 2 generator output connection to the grid.

As noted in Paragraph 2, Unit 2 tripped from a low low steam generator level. The initiating event was the failure of an amplifier card in the electro-hydraulic controls.

The subject card was replaced and the reactor brought critical at approximately 1830 hours on May 26, 1989. The generator went on-line at approximately 0353 on May 27, 1989. The inspector will continue to monitor licensee actions on this event in addition to those previously mentioned in Paragraph 2.

In response to inspection findings documented in Paragraph 5 of Inspection Report Nos. 50-282/88-201 and 50-306/88-201, the licensee contracted with General Electric to disassemble, in the vendor's safety related service shop, several of the molded case circuit breakers whose authenticity was questionable. Eight of the questionable breakers were tested for electrical operation. On April 21, 1989, the inspector, along with representatives from NRR and Region II and III, discussed these results. The NRC representatives, along with the licensee representatives, then witnessed the disassembly by General Electric of three of these eight breakers. This examination provided no evidence that the three internally and externally examined breakers had been modified, readjusted without GE authority or were potentially counterfeit. The licensee plans to disassemble the remaining questionable breakers. The inspector will continue to monitor the licensee's activities in this area.

In conjunction with NRC Information Notice No. 89-44: Hydrogen Storage On The Roof of the Control Room, and a regional request, the inspector reviewed, with the responsible system engineer, the licensee's bulk hydrogen storage facilities. The licensee's storage facility is located in a separate, well ventilated building east of the turbine building. This building is located well removed from the intake ventilation for the control room and auxiliary buildings, with the intake being located approximately 60 feet above and 100 feet south of the hydrogen storage building. The licensee utilizes a system of tanks arranged into ten banks, which may store approximately 30,000 cubic feet of hydrogen gas at any given time.

On April 21, 1989, the Corporate Quality Assurance Department issued finding FG-89-17 on the subject of incorrect radiation monitor setpoints. Specifically, when the licensee was preparing calculated radiation monitor setpoints, a preset isotope mixture was utilized when almost no gamma emitter isotopes were present. If the actual results of the sample had been utilized, the calculated set point would have been at or below the actual setpoints of the radiation monitor, leading to a less conservative setpoint. Further examination by the licensee determined that the method of calculating the calculated radiation monitor setpoint was incorrect. Final analysis of past data by the licensee determined that in all cases, the actual setpoints of the radiation monitor were the most conservative and that the sample results utilized in the revised method of calculating radiation monitor setpoints would yield less conservative setpoints. The licensee intends to continue to use the more conservative setpoints.

As an additional check on plant releases, the licensee verifies that each liquid release batch is sampled and analyzed before it is released to confirm that it will not exceed the maximum permissible concentration (MPC). These limits were not violated, noting that the calculations for MPC were unaffected by the incorrect calculation for radiation monitor setpoints.

In an effort to respond more effectively to current requirements, site modifications and future needs, NSP has made several changes within the nuclear generation organization. Such changes include the consolidation of Nuclear Technical Services and Nuclear Engineering and Construction Departments into the Nuclear Projects Department. The Nuclear Support Group has been restructured to include Nuclear Support Services, Nuclear Analysis Department, and Corporate Security. Additionally, a new position was created of Executive Engineer whose responsibilities will include chairmanship of the Monticello and Prairie Island Safety Audit Committees and corporate sponsor of the Plant Life Extension pilot program relicensing efforts, among others.

The licensee has issued Section Work Instruction SWI-0-30, Reportability of ESF Equipment Actuation, Rev. 0, to administratively expand the list of equipment whose actuation shall be reported under 10 CFR Part 50.72(b)(2)(ii). SWI-0-30 provides additional guidance on what type of actuations warrant reporting. Unplanned manual starts or automatic starts of the following components are administratively considered as reportable:

- 11, 12, 21 and 22 Auxiliary Feedwater Pumps
- 11, 12, 21 and 22 Component Cooling Pumps
- 12 and 22 Diesel Cooling Water Pumps
- 11, 12, 21 and 22 Containment Spray Pumps
- Bus 15, 16, 25 and 26 Load Rejection Signal
- D1 and D2 Diesel Generators
- 11, 12, 21 and 22 RHR Pumps
- Reactor Trip Logic
- Safeguard Actuation Logic
- 11, 12, 21 and 22 SI Pumps
- 121 and 122 Auxiliary Building Special Exhaust Fan
- All ZC (Containment Air Handling) system fans normally in-service
- 121 and 122 Control Room Clean-Up Fan
- 121 and 122 Spent Fuel Special and In-Service Purge Exhaust Fan
- 11, 12, 21 and 22 Shield Building Recirculation Fans

4. Maintenance Observation (71707, 60710)

Routine, preventive, and corrective maintenance activities were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with Technical Specifications. The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures and were inspected as applicable, functional testing and/or calibrations were performed prior to returning components or systems to service, quality control records were maintained, activities were accomplished by qualified personnel, radiological controls were implemented, and fire prevention controls were implemented.

Portions of the following maintenance activities were observed during the inspection period:

- Bearing replacement on 22 main feedwater pump
- Preventive and corrective maintenance on station air compressors
- Replacement of the 22 diesel-driven cooling water pump
- Super compaction of low level waste
- Reinstallation of the section relief valve on the 22 safety inspection pump
- Condenser tube cleaning

Although the vendor manual and calibrated torque wrenches were utilized during the bearing replacement on the 22 main feedwater pump, the inspector noted that vendor specified torque values were not always utilized. Some of the torque values utilized have been verbally passed on among the machinists, who have stated that the values specified by the technical manual are too high and would result in the stretching of the bolting material. Instances of maintenance being performed without the aid of vendor manuals and vendor/industry accepted torque values was previously noted in Paragraph 4 of Inspection Report 50-282/89003(DRP) and 50-306/89003(DRP). The continued concern expressed by the inspector pertains to the need for individuals to have, at the site of maintenance activities, accurate technical information. The inspector will continue to monitor licensee activities in this area.

No violations or deviations were identified.

5. Surveillance (61726, 60710)

The inspector witnessed portions of surveillance testing of safety-related systems and components. The inspection included verifying that the tests were scheduled and performed within Technical Specification requirements, by observing that procedures were being followed by qualified operators, that Limiting Conditions for Operation (LCOs) were not violated, that system and equipment restoration was completed, and that test results were acceptable to test and Technical Specification requirements.

Portions of the following surveillances were observed/reviewed during the inspection period:

SP 2037	Turbine Overspeed Trip Test, Rev. 8
SP 1088	Safety Injection Pumps Test, Rev. 23
SP 1102	11 Turbine-Driven Auxiliary Feedwater Pump Test, Rev. 33
SP 2071	Integrated Leak Rate Test Program, Section 5 - Procedure for Containment Integrated Leak Rate Test, Rev. 9
SP 1106	22 Diesel Cooling Water Pump Test

During the performance of the SP 1106 additional plant parameters were changed to establish a new pressure vs. flow curve. The licensee obtained satisfactory results, plotting numerous points including one of approximately 70 PSIG and 18,000 gpm.

No violations or deviations were identified.

6. ESF System Walkdown (71707)

The inspector performed a walkdown of various portions of the Unit 1 safety injection and caustic addition systems. Observations included confirmation of selected portions of the licensee's procedures, checklists, verification of correct valve and power supply breaker positions to insure that plant equipment and instrumentation are properly aligned, and local system indication to insure proper operation within prescribed limits. During the course of the walkdowns the inspector noted that the secure cards attached to various 480 v motor control center (MCC) breakers isolation status nomenclature differed from the nomenclature listed on the component. Specifically MCC breaker's 2 LAI-AI and CI and 2LA2-B1 were in the off position with secure cards listing the isolation status as open. The inspector considers this discrepancy as minor, although it raises the question on the use of hold/secure cards. The inspector will further examine activities in this area. An additional discrepancy was noted while performing valve lineup verification. Integrated Operations Checklist C1.1.18-1, SI, CS, CA and HC System Checklist Unit 1, Rev. 15, specifies caustic addition valves CA-1-1 and CA-1-3, Inlet Isolation Valves to Control Valve 31941 and 31938, to be in the closed position. The inspector observed the valves in the open position with safeguard hold cards attached. These cards correctly identified the valve with the position as open. The shift supervisor pointed out that C1.1.18-1 was used as initial system line-up and that 1C1.2, unit one startup procedure was utilized later for system realignment as mode changes warrant.

Review of 1C1.2 step 5.22.3 directed the opening of inlet isolation valves to control valves 31941 and 31938 and listed them as the following:

CA-1-2 caustic addition train A to 11 and 12 CS pump and
CA-1-4 caustic addition train B to 11 and 12 CS pump

CA-1-2 and 4, however, are the outlet isolation valves to control valves 31941 and 31938 and were opened with a safeguards hold card attached according to C1.1.18-1.

Noting this discrepancy, the licensee showed the inspector C1-A, Unit Heatup Checklist and Surveillance Procedure SP 2090, Containment Spray Pump and Spray Additive Valve Test, Rev. 25, which called for valve opening and placed the appropriate safeguards hold tag. The licensee initiated action to correct the discrepancy with step 5.22.3 of 1C1.2.

No violations or deviations were identified.

7. Facility Modifications (37701)

As noted in Inspection Report Nos. 50-282/89008(DRP); 50-306/89008(DRP), the Unit 2 Steam Generator Feedwater Control System was being replaced with one of a digital design. The inspectors continued to monitor the checkout tests and trouble shooting of the modification. The inspectors also monitored the feedwater control system startup tests. These tests were conducted at various reactor power levels. Individuals who participated in the system testing were well briefed, knowledgeable of actions and anticipated results and were in constant communication. Minor test procedure changes were processed in accordance with plant administrative controls. No problems were encountered either during plant startup or testing activities. The licensee continues to research the question of whether point to point wiring completely internal to the protection cabinets needed to be installed with lugs applied with a calibrated crimper.

No violations or deviations were identified.

8. Temporary Instructions (255100)

(Closed) TI 2515/100: Proper Receipt, Storage, and Handling of Emergency Diesel Generator (EDG) Fuel Oil.

The licensee has received and is currently reviewing IE information Notice 87-04, Diesel Generator Fails Test Because of Degraded Fuel, dated January 16, 1987. This notice was issued in response to the Arkansas Nuclear One Unit 2 EDG Fuel Oil Starvation event which occurred on June 27, 1986.

The licensee utilizes fuel oil to power two safety related EDGs and two safety related diesel-driven cooling pumps, in addition to the TS-required diesel fire pump and the 121 and 122 heating boilers. The licensee uses Amoco Premier No. 2 diesel fuel oil (100% distillate). The licensee maintains approximately 100,000 gallons onsite. The licensee uses approximately 30,000 gallons per year.

The present fuel oil system does not have an oil recirculation feature. The licensee does not currently utilize any fuel oil stabilizers to prevent oxidation or bacterial growth. The fuel oil transfer system is capable of transferring fuel oil between all of the diesel generator oil tanks, the diesel cooling water pump tanks, the diesel fire pump tank, and the heating boiler tanks. The fuel oil system has a central receiving port through which all oil is received and passed through a filter strainer. All fuel oil is initially transferred to the heating boiler storage tank where the oil is sampled for compliance to specifications before being released into the other TS related fuel oil tanks. To date none of the TS fuel oil storage tanks have been cleaned since initial plant operation.

The licensee's current sampling practice includes a quarterly sampling of the diesel-driven fire pump fuel oil tank and a monthly sampling of the EDG day tank. The TSs differentiate between the day tanks and the fuel oil storage tanks. Tech Spec 4.6.A.1.c requires the licensee to verify that, at least once each month, for each diesel generator a sample of diesel fuel from the fuel storage tank is within the acceptable limits specified in Table 1 of ASTM D975-68 when checked for viscosity, water and sediment. The licensee does not sample the EDG fuel storage tank on a monthly basis. The failure to sample the EDG fuel storage tank on a monthly basis as required by TS 4.6.A.1.c is identified as Violation 50-282/89017-01(DRP).

Day tanks and storage tanks are not checked on a regular basis for water accumulation. Plant history has not revealed the presence of water. Additionally, only one load of fuel oil has been rejected. No fuel oil in storage has failed a sampling surveillance to date.

The receipt fuel oil filter is changed yearly or as needed. The EDGs are equipped with dual filters which allow the filters to be swapped and thereby permit continuous operation. The diesel-driven cooling water pumps, although equipped with dual filters, are not configured to permit the filters to be changed with the pump in operation. The EDG's and the diesel driven cooling pumps utilize differential pressure indicators to indicate filter fouling. Local annunciators associated with day tank level for the EDG's and the diesel-driven cooling pumps are provided and will cause a main control board annunciator to alarm. No annunciators are provided for high differential pressure across the fuel filters.

The fuel oil tanks at Prairie Island as well as the instruments that perform a control function are not seismically qualified. The instruments that provide an alarm were verified as Type 3 equipment. This is not in accordance with IEEE Recommended Practices for Seismic Qualifications of Class 1E Equipment for Nuclear Generating Stations. However, the current design was reviewed and accepted by NRR and does not constitute a violation of NRC requirements.

9. Exit (30703)

The inspectors met with the licensee representatives denoted in Paragraph 1 at the conclusion of the inspection on May 30, 1989. The inspectors discussed the purpose and scope of the inspection and the findings. The inspectors also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any document/processes as proprietary.