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Division of Reactor Inspection and Licensee Performance

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Docket Nos.: 50-282, 50-306

Licensee: Northern States Power Company

Facilities Name: Prairie Island Nuclear Generating Plant Units 1 and 2

Inspection at: Prairie Island Nuclear Generating Plants Unit 1 and 2, 40 miles southeast of Minneapolis, MN

Inspection Conducted: September 21 through November 20, 1992

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EXECUTIVE SUMMARY

For two periods between September 21 through November 20, 1992 (September 21-25, 1992 - phase one; November 12-20, 1992 - phase two), the Nuclear Regulatory Commission (NRC) staff conducted an inspection of shutdown risk and outage management at the Prairie Island Nuclear Generating Plant Units 1 and 2. The intent of the inspection was to assess the quality of the licensee's outage planning and conduct of the outage, with an emphasis on determining if the risk of initiating accident sequences was minimized during shutdown conditions. During the first phase, conducted before the outage, the team assessed the following: (1) management involvement in and oversight of the outage planning; (2) outage schedule, with a focus on relationships among significant work activities and the availability of electrical power supplies, decay heat removal systems, reactor coolant inventory control systems, and containment integrity; and (3) operator response procedures, contingency plans, and training for mitigating events during shutdown conditions. During the second phase, conducted during the outage, the team focused on observing control of ongoing outage work activities and testing to assess the following: (1) the controls, procedures, and training related to the performance of plant activities during shutdown conditions; (2) the working relationships and communication channels between operations, maintenance, and other plant support personnel; (3) outage planning activities for potential impact on shutdown risk, including the scheduling and supervision of work activities and control of changes to the outage schedule; and (4) the degree of management involvement in and oversight of the conduct of the outage. The team also completed NRC Temporary Instruction 2515/113, "Reliable Decay Heat Removal During Outages."

The team found that the licensee's measures to minimize the risk of initiating accident sequences during shutdown conditions were detailed and comprehensive. A formalized shutdown risk program had recently been implemented and was used during the outage. The licensee also showed interest in using it during future outages. The shutdown risk program was sound and appeared to be effective with some exceptions identified by the team. The licensee was encouraged to continue to refine its shutdown risk program and maintain it as a dynamic document.

The plant staff was very knowledgeable and implemented the shutdown risk program competently and professionally. The licensee appeared capable of operating the plant and controlling outages satisfactorily.

The licensee displayed many strengths with the following of particular interest. The work package reviews performed at the work control center contributed to the smoothly run outage. Shutdown risk status boards throughout the plant ensured awareness of key shutdown risk factors. The knowledge level of plant personnel was high, and the shutdown safety assessment training was well carried out.

The team identified several examples where the licensee failed to follow procedures. These included outdated and unapproved procedures left in the field, informal pen-and-ink changes made to controlled procedures, improperly done independent verification checks for valve lineups, failure to control overtime, inappropriately secured equipment, and safety-related systems left open during construction/modification.

TABLE OF CONTENTS

1.0 INTRODUCTION

For two periods between September 21 through November 20, 1992 (September 21-25, 1992 - phase one; November 12-20, 1992 - phase two), the Nuclear Regulatory Commission (NRC) staff conducted an announced pilot inspection of shutdown risk and outage management at the Prairie Island Nuclear Generating Plant Units 1 and 2. The primary objective of this inspection was to assess the quality of the licensee's outage planning and conduct of the outage, with an emphasis on determining if the outage plan and conduct minimized the risk of initiating accident sequences during shutdown conditions. A secondary objective was to assess the ability of the licensee to cope with events that could arise during shutdown conditions in response to inadequate planning or inadequate control of plant operations or work activities.

To achieve these objectives, a team of 11 inspectors conducted the inspection in two phases: (1) during the pre-outage planning period and (2) during the outage.

During phase 1, the team assessed

(1) management's involvement in and oversight of the outage planning

(2) the outage schedule, focusing on the coordination of significant work activities and the availability of electrical power supplies, decay heat removal systems, reactor coolant system (RCS) inventory control, and containment control

(3) operator response procedures, contingency plans, and training for mitigating events involving a loss of decay heat removal capability, loss of RCS inventory, and loss of electrical power sources during shutdown conditions

During phase 2, the team assessed

(1) the implementation, controls, procedures, and training related to the performance of plant activities during shutdown conditions

(2) the working relationships and communication channels between operations, maintenance, and other plant support personnel

(3) outage planning activities including the scheduling and supervision of work activities and control of changes to the outage schedule

(4) the degree of management involvement in and oversight of the conduct of the outage

The team has characterized the findings in this report as deficiencies or observations. Deficiencies are the apparent failure of the licensee either (1) to comply with a requirement or (2) to satisfy a written commitment or to conform to the provisions of applicable codes, standards, guides, or other accepted industry practices when the commitment has not been made a legally binding requirement. Observations are items considered appropriate to call to the attention of the licensee's management and have no apparent regulatory basis.

2.0 PHASE ONE - OUTAGE PLANNING AND SCHEDULING

The team examined the licensee's process for outage planning and scheduling. Particular emphasis was placed on determining if the licensee incorporated risk management considerations into the maintenance and outage scheduling process. Emphasis also was placed on determining how the licensee used the planning and scheduling process to control work activities used for managing shutdown risk.

2.1 Outage Risk Assessment Plan

The team reviewed the licensee's pre-outage planning process for the dual-unit outage with specific emphasis on shutdown risk considerations. The outage schedule had not yet been completed during the pre-outage inspection phase. The licensee had established a shutdown risk philosophy to identify and schedule potentially significant maintenance and construction tasks that could influence total plant risk. The team reviewed the outage risk assessment plan as it related to the licensee's program.

Specifically, Administrative Work Instruction (AWI) 5AWI 3.15.4, Revision 0, "Planned Outage Management," required that the licensee maintain a minimum defense in depth for each of the key safety functions described in Nuclear Management and Resources Council (NUMARC) 91-06, "Guidelines for Industry Actions To Assess Shutdown Management." The instruction emphasized that this should be considered during the outage planning process and noted that the licensee should schedule the level and sequence of activities to avoid undue risk as a result of equipment unavailability.

Further, a shutdown safety assessment was performed before the start of the outage based on Checklist PINGP 1102 (Unit 1) or PINGP 1103 (Unit 2). These checklists were developed to provide a status indication (i.e., color codes green, yellow, orange, and red). This status was based on the availability of the systems, structures, and components needed to support the following key safety functions: (1) decay heat removal, (2) inventory control, (3) power availability, (4) reactivity control, and (5) containment closure. For example, an orange condition shows that the minimum redundant equipment is available to support the

key safety function. By procedure, entering an orange status requires a contingency plan and review by the operations committee before scheduled implementation.

In addition, the licensee had completed a limited probabilistic risk assessment (PRA) shutdown study based on the proposed outage activities. The study showed that manual operator actions were the primary source for risk during shutdown. The team interviewed outage planning personnel who cited the need for increased awareness during electrical switching and cooling (service) water switchover operations as the principal benefit that resulted from the PRA study.

The licensee used a Plan-a-Log board to schedule the sequence of significant outage activities. The outage scheduling specialist (OSS) developed the outage schedule using his personal experience and interacting with the responsible work groups. Once completed, the Plan-a-Log board outage schedule was reviewed by the OSS, the outage planning team (OPT), and the plant scheduling and services supervisor to ensure that a minimum level of defense in depth was maintained throughout the outage based on the shutdown safety assessment guidelines in 5AWI 3.15.4. Changes made to the outage schedule as a result of the multi-discipline review eliminated the simultaneous scheduling of activities with conflicting prerequisites and appeared to minimize the potential impact of personnel error on the availability of safety-related equipment. Contrary to typical Prairie Island plant outages of 22 to 32 days, the subject dual outage represented a significant challenge to the outage planning process given the extensive electrical and mechanical modifications.

Overall, the licensee's process for scheduling outage work activities ensured that the schedule reflected an awareness of shutdown risk. This adhered to the licensee's philosophy of minimizing shutdown risk.

2.2 Planning, Scheduling, and Preparation of Modification and Work Packages

The purpose of this part of the inspection was to assess the licensee's process for assembling and reviewing work and modification packages. The team also reviewed the planning and scheduling aspects associated with the outage.

The licensee controlled the development of outage work packages through Administrative Control Directive (ACD) 5ACD 3.2, "Work Control," and its associated administrative work instructions 5AWI 3.2.1 through 3.2.8. Outage-related work efforts were documented under the program with the exception of routine surveillance activities. The ACD included the designation of a responsible individual, either a plant contact or system engineer, to oversee all work or major modifications on a

specific plant system. Technical and quality reviews of individual work packages were incorporated into the overall development process. The degree and depth of reviews were dependent on the work scope.

The licensee conducted an additional and separate pre-outage review of the work packages in an attempt to further minimize the distribution of incomplete or incorrect materials. The review was performed by three off-shift licensed operators. It included an evaluation of the proposed system alignments and personal safety measures and the incorporation of numerous human performance enhancements into the work package materials.

The team's review of a sampling of work packages prepared for the dual-unit outage showed that the packages included the necessary supporting documentation and procedures.

The licensee managed the development and conduct of the dual-unit outage under 5AWI 3.15.4, Revision 3, "Planned Outage Management." The work instruction included generally adequate assignments of responsibility for performing the different outage management activities. The instruction was revised twice during the inspection to clarify management's expectations and to provide additional guidance for the conduct of outage-related work activities.

The team attended a monthly pre-outage planning meeting conducted by the OSS. The meeting was conducted informally, and the participants were provided with the outage status. The team also attended an outage briefing conducted by the plant scheduling and services supervisor, who discussed the licensee's shutdown risk philosophy with the health physics group. The briefing provided a good overview of management's expectations regarding the conduct of outage activities. The team also noted that as of September 25, 1992, procedures required for the outage (e.g., "Reactor Draindown Abnormal and Operating Procedures," D-2 series) were not available. However, procedures were issued and this problem was resolved before the steam generator tube leakage forced outage was started. This forced outage occurred after phase 1 of this inspection and before the scheduled refueling outage.

The refueling outage schedule was prepared and reviewed under the auspices of the OSS and with the assistance of the OPT, a multidisciplinary review group. Pre-outage preparations were performed according to the schedule developed by the OPT to ensure the timely development and review of safety-related activities. During the first phase of the inspection, the team found that a significant number of outage work packages had not received technical reviews within the milestones dictated by management and were not yet included in the outage schedule (700 of 1200 work packages). At the start of the outage, the licensee

had reduced the backlog of incomplete outage work packages by approximately two-thirds. However, the late completion of these activities prevented the licensee from entering the outage with a fully developed, reviewed, and approved outage schedule for Unit 2. The completed Unit 2 schedule was approved during the first week of the outage. The team felt that this delay was a result of the forced outage. The team did not identify any safety-significant impacts associated with the delayed development of the Unit 2 outage schedule.

Overall, the licensee's outage scheduling process appeared to properly focus attention on safety-significant activities and effectively implemented the licensee's philosophy of minimizing shutdown risk. The additional and separate pre-outage reviews, though informal, were a strength.

2.3 Training

In accordance with Generic Letter 88-17, "Loss of Decay Heat Removal," which specifies that training should be provided shortly before entering a reduced inventory condition, the licensee conducted classroom training in the following subjects before the outage: (1) Outage Risk, (2) Fuel Handling, (3) Reduced Inventory Operations, (4) Core Analysis, (5) Control Room Evacuation (Fire), Safe Shutdown Procedure/D1 Diesel Generator Operations, and (6) Modifications and Industry Events. The training was conducted during requalification cycle 92-07, which began August 10 and ended September 18, 1992.

The team reviewed the training attendance records and found that all onshift operators except for five had attended all of the training. Three of those individuals failed to attend "Modifications and Industry Events," one individual failed to attend "Reduced Inventory Operations," and one individual failed to attend both "Outage Risk" and "Fuel Handling." However, this was not a concern for the team given the relatively small number of individuals involved and the small number of classes not attended.

The simulator did not have the capability for modeling mid-loop operations. It was used for providing training on accident scenarios related to shutdown conditions, which included loss of residual heat removal (RHR) cooling. The licensee was developing additional shutdown scenarios, which included loss of power to the RHR system.

The team reviewed the training material associated with the electrical modifications being incorporated at Unit 2 during the outage. These modifications included the addition of (1) two diesel generators that would supply 4.16-kV safety buses and (2) two 480-V safety buses. Additionally, safety bus nomenclature was changed for the 4.16-kV buses to make it more

consistent with that at Unit 1 and for the 480-V buses to address the addition of the two new buses. The learning objectives and content of the training material adequately addressed the electrical modifications, and the training material was sufficient. A sample of shift licensed operators questioned about the electrical modifications and their impact on plant operations displayed an adequate level of knowledge in this area. The simulator was modified to reflect these modifications in June 1992 so that training could be conducted before the outage. Training was completed before the start of the outage.

2.4 Procedures

The team reviewed the technical content of, and walked through selected normal and abnormal operating procedures related to the modified electrical distribution system, and examined the procedures that had been developed for shutdown conditions. The team noted that procedure development had received low priority. For example, operating procedures for the new Unit 2 station blackout (SBO) diesel generators were not available for use. However, these components were credited as available power sources in the Unit 2 shutdown safety assessment. Examples of lack of attention to detail were noted in the development of procedures, and adherence to procedures. The team identified the following deficiencies as part of Deficiency 92-201-01, "Failure To Follow Procedures":

- Procedure 5ACD 1.5, Revision 11, "Procedure Control," step 6.5.3.g stated that "outdated or deleted procedures shall be recovered and destroyed." However, outdated, unapproved Procedures C20.5-1, Revision 4, "4.16-kV Breaker Rack In/Out," and C20.6-1, Revision 2, "480-V Breaker Rack In/Out," were found in the Unit 2 safety related switchgear area. These procedures could have been used to rack breakers in or out on the safety-related buses. The team's understanding was that these unapproved procedures had not been used.

  The licensee stated that approved Procedures C20.5-1, Revision 4, and C20.6-1, Revision 2, were available in the plant for use. The team compared the approved and unapproved procedures and found them to be essentially identical. The licensee took prompt corrective action to remove the unapproved procedures from the area.

- Abnormal Operating Procedure (AOP) 2C20.7 AOP 1, Revision 0, "Failure of D5 or D6 Keep Warm System," referred to Procedure 2C20.7, Revision 0, "D5/D6 Diesel Generators," to run the diesel generators periodically as part of the contingency actions if the diesel keep warm system failed. However, Procedure 2C20.7, Revision 0, was still in draft form and not available for implementation. It also would

have been relied on to start the D5 or D6 diesel generator if either failed to start automatically. The diesel generators were a source of power to Unit 2 safety-related buses, including those for RHR cooling, if offsite power was lost.

The team concluded that the unavailability of Procedure 2C20.7, Revision 0, was not an immediate safety concern with regard to power availability for RHR cooling at Unit 2 for the following reasons. Two independent offsite power sources and both D5 and D6 diesel generators would have to fail or be unavailable as a result of maintenance for a loss of ac power to Unit 2 safety buses to occur. The licensee stated that the D5 and D6 diesel generators had been tested and could power the safety buses if a loss of offsite power occurred. Additionally, offsite power and one safety diesel generator were available for Unit 1. Unit 1 safety power could be cross tied to Unit 2 if needed. Unit 1 was defueled and did not require RHR cooling.

The team reviewed Procedure 5AWI 3.15.4, Revision 3, "Planned Outage Management," which describes the organization, delineates responsibilities, and specifies the requirements necessary to ensure planned outages are conducted safely. The team was concerned about how forced outages would be conducted under this procedure. In response, the licensee made changes to the procedure to ensure that the shutdown risk philosophy would be consistently implemented for forced outages when the unit reaches cold shutdown conditions.

Another concern pertained to adherence to the NUMARC guidelines, since the licensee did not have an approved procedure for containment closure. The draft containment closure procedure had not specified the necessary response times (i.e., time to boiling curve) and the capabilities necessary to close the containment. The licensee addressed these concerns promptly.

2.5 Industry Event Review

Procedure 5ACD3.7, Revision 7, "Operation Experience Assessment," listed the guidelines for screening and assessing operation experience documents. It provided detailed requirements to screen, assess, and document reviews of operational events to ensure their applicability to Prairie Island. If the event was applicable, the event evaluation group had to assess the impact and provide recommendations to management to address the issue. The plant staff would then consider immediate and long-term implementation of these recommendations and the associated corrective actions to be taken. To ensure that the industry events were assessed according to the procedures, the team reviewed 12 NRC information notices, two NRC bulletins, one Institute of Nuclear Power Operations (INPO) significant operation event report, and seven INPO significant event reports.

It also reviewed related documents that formed the bases for the corrective actions as well as training documents to verify that the licensee's staff was provided with proper training. The team considers that the licensee program to evaluate and address industry events is a strength.

2.6 Probabilistic Risk Assessment

The team reviewed the licensee's shutdown PRA to determine how the PRA identified the relatively higher risk outage configurations and how the conclusions from the PRA were integrated into the outage plan. In evaluating the PRA and the validity of the conclusions, the team found the following:

(1) Various changes in vessel level, temperature, pressure, containment integrity, RCS integrity, and decay heat during an outage define how much time the operator has to perform identified actions to recover decay heat removal before core damage. The licensee's assessment divided the outage into segments that accounted for changes in vessel level, decay heat, RCS integrity, and availability of support and essential systems.

(2) Loss of offsite power, loss of component cooling water, loss of cooling water, and loss of RHR were included in the PRA as potential shutdown risk initiators. The licensee evaluated the likelihood that the operator could overdrain the vessel and considered the likelihood that hardware faults could result in failure of the RHR system.

(3) The licensee identified what operator actions and systems could be used to successfully prevent core damage given a shutdown risk initiator. However, the success criteria were based on overly conservative and simplistic assumptions.

(4) The licensee used event trees to identify and quantify shutdown accident sequences per segment per shutdown initiator and fault trees to determine system availability. Maintenance unavailability was based on the outage schedule as of August 10, 1992.

Although the analysis was based on conservative assumptions, the method identified the risk dominant segments of the outage based on the outage schedule as of August 10, 1992. Operator error was identified as a large contributor to shutdown risk. However, it should be noted that the insights derived from the PRA could have been enhanced if the conservatisms were removed.

Since the analysis was not completed during the inspection, the PRA group had not discussed the results with the outage coordinator. However, the PRA group planned to discuss the results with the outage coordinator before the outage. The PRA

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contact mentioned that should the outage schedule change, the PRA group would reevaluate the outage schedule, only if requested. It should be noted that outage risk is outage schedule dependent. Therefore, the licensee's risk analysis did not accurately represent the plant's current outage risk, since the outage schedule had changed. For example, the licensee's analysis did not assume that either unit would enter mid-loop conditions, but Unit 1 went into a forced outage and mid-loop operation so that the steam generator (SG) tubes could be repaired. The team felt that the PRA should be a dynamic document. This would enhance the overall shutdown risk program.

2.7 Conclusion

The licensee's s[illegible] sidered minimizing the potential and consequences of s[illegible] events when scheduling maintenance and modification acti[illegible] Also, the outage scheduling process was properly focused, [illegible]gh it still could be enhanced, and work packages had under[illegible] a strong separate pre-outage review. Training and the industry event review process were sound; however, deficiencies associated with procedures existed.

3.0 PHASE TWO - OUTAGE IMPLEMENTATION

During the second phase of the inspection, the team observed outage activities and assessed the quality of the conduct of these activities and management's involvement in and oversight of the Unit 1 and 2 outage. The team emphasized the direct observation of operations, maintenance, and surveillance activities and paid particular attention to the control and coordination of activities from the main control room and the work control center. The team also attended daily status briefings and observed shift turnovers. The team toured many plant areas during both day and back shifts to assess the adequacy of maintenance and surveillance activities, housekeeping, and work practices.

3.1 Control of Plant Operations and Work Activities

To evaluate the involvement of operations personnel in shutdown activities, the team observed control room activities, control of plant operations, and outage activities on a periodic basis throughout the inspection. The team also attended morning outage meetings and observed several shift turnovers followed by shift turnover meetings.

The morning outage meetings were attended by representatives from various departments in the plant. Its agenda included briefings from the outage safety assessment team and discussions on major plant evolutions, critical paths, operations, maintenance, instrumentation and control, and electrical systems. Individual shift turnovers were conducted in the control room and

in the work control center for the plant attendants, assistant equipment operators, reactor operators, lead reactor operators, shift supervisors, and shift managers. The team observed the turnovers for control room operators and shift supervisors. These turnovers included detailed walkdown of panels and discussions of significant equipment and systems not available for service, operational plans, and new administrative procedures affecting the oncoming shift. A shift change status was generated to document the essential information discussed during the turnover and retained for the record. Following the individual turnovers, shift turnover meetings attended by the outage planning manager and the oncoming staff were held. During these meetings, the shift work was discussed with the safety assessment team providing a summary of key plant evolutions and vulnerabilities. A turnover book for each unit that contained daily orders, operation notes, safety assessment sheets, and shift change status was kept in the control room.

The operators' log and the electrical systems log in the control room contained only the significant changes that occurred during the shift. More detailed plant evolution records were contained in the signed plant procedures such as Procedure 1C1.3, "Unit 1 Shutdown."

Shift supervisors adequately monitored activities for which they were responsible. Communications between operations personnel and the work control center, maintenance, and other groups were good. The work control center was staffed with licensed senior reactor operators (shift supervisors) who reviewed work packages in advance of the responsible shift supervisor's review. The use of the work control center proved very valuable and significantly reduced the unnecessary noise and activity level in the control room. It also allowed the operators to concentrate on monitoring plant conditions.

Training personnel with operating licenses were assigned to each crew and were responsible for updating the shutdown safety assessment (SSA) checklist maintained in the control room and the four SSA status boards strategically located throughout the plant. The updates occurred once each shift and any time outage-related activities could have affected SSA conditions. The SSA status was provided at shift meetings and at daily outage meetings.

Control room activities were well managed, and operators were aware of activities that would affect the current plant status. These activities were discussed with the operators before work was begun. Professionalism was maintained in the control room during the inspection, and minimum operating crew staffing requirements in the technical specification were met.

Adequate time was allocated for the shift turnovers, and detailed information transfer and control room walkdowns were conducted to ensure continued safe shutdown activities.

3.1.1 Electrical Power Availability

Work Request (WR) S8822-ES-Q, "Isolation of 13.8-kV Bus CT11 & CT12," required entry into an orange condition for the Unit 1 power availability safety function. Diesel generator D1 and the offsite power source, via the 1R transformer, were the only power sources available to engineered safety features (ESF) bus 15. ESF bus 16 was out of service for maintenance. The contingency procedure developed to restore power was technically correct. Any delay or errors introduced when performing the contingency procedure would have had minor safety significance (e.g., potential heatup of the spent fuel pool).

3.1.2 Overtime Control

The team reviewed the licensee's administrative control of overtime with respect to applicable overtime restrictions. The team reviewed an overtime computer printout of payroll records and time cards from October 4 to November 14, 1992. The licensee's administrative control of overtime was delineated in Technical Specification 6.1 and Procedure 5ACD, Revision 13, "Plant Operations." The overtime restrictions were the same in both documents, and any deviation from the overtime restrictions required the plant manager's approval.

The records reviewed showed that the licensee was tracking any deviations from overtime restrictions. The licensee identified five instances of plant personnel exceeding the overtime requirements without prior approval of the plant manager. Three occurred in the Engineering Department, and two in the Operations Department. Only one of these five instances took place during the outage. This is part of Deficiency 92-201-01, "Failure To Follow Procedures."

The licensee addressed the potential overtime problems in two memoranda to all site personnel issued before the outage. The memoranda reminded plant employees of the overtime requirements. The team verified that the importance of adhering to overtime limitations was reinforced by licensee management.

3.1.3 Mid-loop Operations - Forced Outage

During a forced outage at Unit 1 (October 1992), the crew performed a reactor coolant system (RCS) draindown and operated the unit at mid-loop condition. The team was not on site during these activities. The team did, however, review the procedure for this evolution, 1D2, Revision 0, "Reduced Inventory Operations," and discussed this evolution with a sample of

operators and operations engineering-procedure group personnel. The evolution was completed without incident, and the procedure was adequate.

The team compared the procedure with its predecessor, D2, Revision 21, "RCS Reduced Inventory Operations," and found that the new procedure

- was specific to Unit 1 rather than being generic
- required a pre-job briefing
- specified dedication of operators and supervision for the evolution
- controlled the RCS drain rate by specifying various drain paths and hold points
- incorporated contingency actions to address loss of residual heat removal (RHR) as a result of a loss of the electrical power supply

These procedural changes were enhancements that provided the operators with improved guidance to conduct the evolution.

3.1.4 Decay Heat Removal Capability

According to NRC Temporary Instruction (TI) 2515/113, "Reliable Decay Heat Removal During Outages," the team evaluated the following specific areas:

- increased vulnerability during reduced inventory and availability of electric power sources
- procedures to ensure forced circulation decay heat removal and natural circulation decay heat removal

During this inspection, Unit 1 had been defueled and Unit 2 had fuel in the vessel with the refueling cavity filled. Because Prairie Island (PI) did not enter mid-loop operation or reduced reactor coolant system inventory during the scheduled outage, the risk during the shutdown was reduced. To satisfy the RHR requirements in Technical Specifications (TS) 3.1.A.1.c and 3.8.A.1.g while at cold or refueling shutdown conditions, the licensee issued Technical Specification Interpretation (TSI) 3.1-4, which stated that the RHR loop is considered operable as long as the following conditions are satisfied:

(1) The RHR pump and its associated heat exchanger are available.

(2) Component cooling (CC) is available to the RHR heat exchanger within the capacity of the available CC pumps.

(3) Cooling water is available to the CC heat exchanger from an available cooling water header.

(4) Two cooling water pumps, one of which is a safety-related cooling water pump, are available to supply cooling water.

Procedure 5AWI 3.15.4, Revision 3, stated that a system or component is available when the equipment or component is "in service or can be placed in service in a functional or operable state by immediate manual or automatic actuation." In addition, in a memorandum to the operating committee issued on November 2, 1992, by the plant scheduling and services supervisor stated that as long as these pumps will function, i.e., they have electrical power available, the RHR loop is considered operable and applicable technical specifications are satisfied.

The team discussed the accuracy of this interpretation with the plant scheduling and services supervisor and reviewed Operating Procedures 1C15, Revision 3, "Residual Heat Removal System," and 1D2, Revision 1, "Draindown to 1' Below the Reactor Flange and Refill to Refueling Level." These reviews and discussion showed that the above interpretation did not meet the technical specifications for the operability of the RHR system. However, it appeared to the team that at no time did the licensee enter the condition identified in the TSI. This is Observation 92-201-02, "Availability of RHR."

The licensee's shutdown safety assessment program was significant in ensuring that the station personnel were aware of the following key elements: plant vulnerabilities, performance of assigned work, and the status of outage activities. This assessment program was implemented by licensed operators who performed the activities prescribed by the shutdown safety assessment checklist. These activities were completed at least once per shift or whenever events occurred that might influence any of the following shutdown key safety functions: decay heat removal, inventory control, power availability, reactivity control, and containment integrity. This checklist was unit specific and controlled by Procedure 5AWI 3.15.4, Revision 3. Licensee operators in the Training Department performed the assessment according to the appropriate checklist.

The inspection team witnessed work activity associated with communications in the control room and reviewed several completed shutdown safety assessment checklists. The team found that the shutdown safety assessment process was well conceived and licensee personnel were thorough in performing the assessment. However, it noted minor errors in the completed checklists.

The team reviewed Procedure 1C15, Revision 4, "Residual Heat Removal System," for establishing forced circulation decay heat removal and Table 4 of Procedure 1D2, Revision 1, "Contingency Actions for Loss of All AC Power While at Reduced Inventory Conditions," for establishing natural circulation decay heat removal with the reactor coolant system manways installed. The establishment of RHR capability was documented in step 5.2.18c of Procedure 1C1.3, "Unit 1 Shutdown." These procedures were adequate in describing the methods to establish forced circulation and natural circulation under different conditions.

In addition, as part of TI 2515/113, the team gathered information to address the following areas:

- Are one offsite power source and one onsite power source available to each required shutdown load?

  During the dual-unit outage, the station blackout (SBO) modifications required that the Unit 2 ESF buses be deenergized and taken out of service. The licensee flooded the Unit 2 reactor cavity and maintained one RHR train operable according to the technical specifications. However, no requirement specified that at least one offsite power source and one onsite power source be available to each of the required ESF buses. The licensee considered any power feed to the load as sufficient to meet the operability requirement.

- Determine if dc power, backed up by battery, is available to required loads when battery testing maintenance is being performed.

  The licensee planned to perform battery testing and maintenance activities. The dc power system design permits dc power to be available to the required loads through cross-tie connections to alternate dc sources. During maintenance and testing activities during the outage, the licensee used cross-tie connections.

- Are nonstandard electrical lineups properly analyzed and does the licensee use approved procedures for such lineups?

  Responsible engineers informed the team that the temporary electrical connections were controlled by two means: a temporary power modification for non-safety-related power feeds or under the work request package process.

- Are operators prepared to manually control electric power systems if automatic control systems are disabled for maintenance?

Operating personnel informed the team that crews were trained on the use of emergency operating procedures (EOPs) and applicable abnormal operating procedures (AOPs). This training allowed the use of manual control of electric power systems as needed. The licensee has developed AOPs for shutdown conditions.

* Do periods of increased vulnerability coincide with the minimal availability of electric power sources?

  The licensee maintained at least a yellow condition (i.e., three power sources including the use of unit bus ties for two buses) before completing the core off-load process for Unit 1 and the flooding for Unit 2.

* Does the licensee declare an emergency diesel generator (EDG) inoperable when its field flashing source is removed from service for maintenance or testing?

  The licensee declares the EDG inoperable when its dc battery bus (field flashing source) is removed from service.

3.2 Control of Maintenance and Surveillance Activities

To determine whether the licensee had adequate control over maintenance and surveillance activities, the team reviewed work packages, observed the coordination of work activities in the field, inspected isolated equipment, and observed post-maintenance testing.

3.2.1 Work Packages and Modifications

The team reviewed several modification and work packages to determine if safety requirements were being properly implemented. An apparent contradiction existed in modification package No. 92Y170, "Cooling Water Header Replacement." In the Design Inputs Checklist, Section 1.b., the licensee stated, "There will be no change to the cooling system design flow or pressure. This was verified by the Thermal-Hydraulic Model of the Cooling Water System." In the Safety Evaluation - Revision 0, Section 5, paragraph 1, of the same package, the licensee stated, "The usage of heavier wall cooling water header pipe plus the added epoxy coating on the inner diameter of the piping will change the system flow capacities. The hydraulic analysis being performed as part of this modification will provide assurance that an unreviewed safety question has not been introduced."

In response to the team's concern, the licensee stated that system flow would change because of the reduced inside diameter of the piping due to the epoxy coating applied to the inside of the piping, but this change would not be significant enough to warrant a change to the Updated Safety Analysis Report. The

licensee also stated that the hydraulic analysis being performed by the contractor (United Engineers and Constructors) would not be available until the replacement of the piping was near completion. This explanation was reasonable and accepted.

The team's review of station modification No. 89Y976 Parts A and C pertaining to the installation of the SBO diesel generators showed that detailed planning had been performed to control the work and associated risks resulting from the electrical switching operations.

All the other modification packages reviewed by the team appeared to be sufficiently analyzed and properly addressed any safety concerns.

A sampling of mechanical, electrical, and instrument and calibration work packages developed for and in use during the outage addressed the appropriate permits, quality control inspections, safety considerations, radiological controls, and authorization signatures. The overall quality of work package materials was adequate.

During the implementation of a number of work packages in the field, licensee personnel had the appropriate procedures and equipment to perform the work and generally used and signed off the procedures according to the governing administrative procedures. The team informed the licensee of several minor examples of failure to properly change and/or follow procedures such as operations committee Procedure EP 17-41. This failure is part of Deficiency 92-201-01, "Failure To Follow Procedures."

3.2.2 Coordination of Work Activities and Schedule Changes

The licensee controlled the performance and timing of work activities through (1) the outage schedule developed and approved before the outage, (2) daily morning meetings and planning sessions that included the use of a well- conceived rolling 3-day work schedule, and (3) the functioning of a work control center (WCC) developed specifically for outage work management. Changes to the overall outage schedule, including the timing of emergent work, were controlled under Procedure 5AWI 3.15.4, "Planned Outage Management," on the basis of the expected impact of the work on the shutdown safety assessment. Minor schedule changes (i.e., status changes from green to yellow) were controlled by the shift supervisor. Review by the outage planning team and the operations committee was required before planned significant changes (i.e., status changes to orange) to the outage schedule. During the outage, the licensee twice entered conditions of reduced defense in depth, as indicated by an orange shutdown safety assessment (SSA) condition. These conditions were unplanned and were not included in the original approved outage schedule. The licensee's response to the events was well

conceived and executed in accordance with the administrative directives.

WCC activities, as managed by a licensed shift supervisor and reactor operator for each unit, included most of the functions normally accomplished by licensed control room staff with the exception of the authorization to implement work packages that require the placement of new equipment control tags. WCC staff also served as a communications link between workers in the plant and personnel in the control room.

3.2.3 Equipment Isolation

During its review of the licensee's process for isolating equipment or systems to conduct maintenance or modification work, the team verified that appropriate clearances had been obtained.

The licensee controlled the isolation and restoration (I&R) of equipment during the outage using Procedure 5ACD 3.10, "Equipment Control," and the associated administrative work instructions (AWIs). Licensed operators, working as part of a pre-outage work package review team, assessed the adequacy of proposed work packages and developed I&R equipment control tags and associated paperwork for the majority of outage work packages. During this process, an operator inappropriately deleted a requirement for independent verification (IV) of numerous equipment control tags. This error was identified by the licensee during the first week of the outage. Although the superintendent of plant operations issued a memorandum to correct the error, the plant staff continued to authorize the start of work without completion of the required IVs for approximately 1 week. Work already in progress was also allowed to continue without completion of the IVs for approximately 1 week. During its review, the team identified additional work packages for which IVs were required and had not been completed before the duty shift supervisor authorized the start of work. The licensee performed the missed IVs and did not identify any mispositioned equipment. This is part of Deficiency 92-201-01, "Failure To Follow Procedures."

During its review of the licensee's field implementation of I&Rs, the team found that the equipment examined was in the proper position and properly labeled. The paperwork and computer records used to track the status of individual components were complete and accurate with the exception noted above. During system walkdowns, the team found that equipment isolations, associated with ensuring the availability and operability of safety-related systems, were adequate.

During these walkdowns, the team identified a number of lapses in the licensee's implementation of its color coding program for unit/train equipment control tags. This program was initiated by the licensee before the outage to minimize the potential for

personnel errors. In an August 13, 1992, meeting with NRC Region III personnel, the licensee stated that they intended to institute human performance measures (e.g., system train and unit confirmation checks) during the dual-unit outage to reduce the risks due to human errors. However, the color coding program was not consistently used for numerous equipment control tags developed and issued after the start of the outage.

3.2.4 Post-Maintenance Testing

The team's review of a sampling of work packages showed that each package reviewed included specific post-maintenance testing requirements and the designation of an individual responsible for completing and evaluating the test results before the equipment was returned to operation. The team did not observe any problems in this area.

3.3 System Walkdowns

During a walkdown of the spent fuel pool cooling system the team found that the system valves were correctly aligned for required system operations. Also, the labeling of valves and components was adequate.

The team also conducted pre-outage and outage walkdowns of the normal and emergency power supply components and switchyard areas. These walkdowns included the vital dc batteries/battery chargers, the vital 480-V/4.16-kV switchgear, the EDGs, the auxiliary and startup power transformers, the vital inverter power supplies, and the 345-kV/161-kV switchyard areas. The housekeeping conditions in the subject areas were acceptable, and the switchyard areas seemed not to be vulnerable to vehicular hazards. The controls specified in Procedure 5ACD 3.15, Section 6.8, "Operation of Motorized Vehicles in the Substation and in the Vicinity of Overhead Transmission Lines," were adequate to minimize the potential for damage.

3.4 General Plant Area Walkdowns and Assistant Equipment Operator Rounds

The team conducted walkdowns of the plant areas and accompanied assistant equipment operators (AEOs) during routine rounds. The AEOs completed the rounds in an orderly fashion and were very observant of ongoing outage activities. One AEO found that a danger barrier (red and black tape) was not in place around an open breaker cubicle at an unattended motor control center (MCC) and immediately corrected this condition.

Besides the set rounds, one AEO was required to open some breakers on various MCCs in support of ongoing electrical maintenance as requested by the control room personnel. The AEO verified that the MCC and the breakers were the correct ones

before repositioning the breakers. The AEO logged the breaker positions before and after the evolution as requested and informed the control room when the evolution was complete.

The material condition of the plant areas toured during the rounds was good. However, the team found instances of material supported by, or attached to, safety-related conduit and of systems left open and susceptible to the intrusion of foreign material. These instances are part of Deficiency 92-201-01, "Failure To Follow Procedures."

3.5 Conclusion

Overall, operations management, supervisors, and operators were very knowledgeable and cognizant of outage activities, and the program was sound in the areas of post-maintenance testing. However, deficiencies existed in regard to the following: overtime control, the independent verification of equipment isolation, systems left open, and the implementation of the licensee's color coding program for unit/train equipment control tags.

4.0 EXIT MEETING

On November 20, 1992, the team conducted an exit meeting at the Prairie Island Nuclear Generating Plant Units 1 and 2. NRC and licensee personnel attending this meeting are listed in Appendix B. The licensee did not identify as proprietary any materials given to the inspection team. During the exit meeting, the team summarized the scope and findings of the inspection.

APPENDIX A

DEFICIENCIES

DEFICIENCY 92-201-01

FINDING TITLE: Failure To Follow Procedures (Sections 2.4, 3.1.2, 3.2.1, 3.2.3, and 3.4)

DESCRIPTION OF CONDITION:

The licensee failed to adequately follow its administrative procedures as discussed below.

1. During plant tours, the team found one instance of systems left open and susceptible to the intrusion of foreign materials contrary to Procedure SWI-M-20. Cooling (service) water control valve 39403, which supplies Unit 1 containment fan coil units, was removed (Work Request S7507-ZX-Q), which resulted in an opening approximately 1 foot in diameter in the system without any provisions to prevent foreign material from entering the opening.

2. An operator inappropriately deleted a requirement specified in Procedure 5AWI 3.10.1 for independent verification (IV) of numerous equipment control tags. Although this error was identified by the licensee, the plant staff continued to authorize the start of work without completion of the required IVs for approximately 1 week. This was not in accordance with Procedure 5ACD 3.10.

3. During walkdowns of the plant, the team found two instances of materials supported by or attached to safety-related conduit contrary to Procedure D80. In the auxiliary feedwater (AFW) room, scaffolding was constructed to a height of approximately 10 feet above the floor with the highest platform supported on one end by numerous safety-related equipment electrical conduits. In the Unit 2 containment, an unattended ladder was tied off to a bundle of safety-related equipment electrical conduit.

4. Procedure 5ACD 1.5, Revision 11, "Procedure Control," step 6.5.3.g stated that "outdated or deleted procedures shall be recovered and destroyed." However, outdated, unapproved Procedures C20.5-1, Revision 4, "4.16-kV Breaker Rack In/Out," and C20.6-1, Revision 2, "480-V Breaker Rack In/Out," were found in the Unit 2 safety-related switchgear area. These procedures could have been used to rack breakers in or out on the safety-related buses. The team's understanding was that these unapproved procedures had not been used.

5. Unapproved pen and ink changes had been made to operations committee (OC) Procedure EP17-41, "Maintenance of Prairie Island Allis Chalmers 480 Volt Breakers LA-600 Manually Operated Breakers 123 and 126." Specifically, the method for closing the breaker manually had been revised, and a step had been added, leaving the breaker in the open position; both breakers were found open by the team.

6. Abnormal Operating Procedure (AOP) 2C20.7 AOP 1, Revision 0, "Failure of D5 or D6 Keep Warm System," referred to Procedure 2C20.7, Revision 0, "D5/D6 Diesel Generators," to run the diesel generators periodically as part of the contingency actions if the diesel keep warm system failed. However, Procedure 2C20.7, Revision 0, was still in draft form and not available for implementation. It also would have been used to start the D5 or D6 diesel generator if either failed to start.

7. The team identified a deficiency in the licensee's compliance with the overtime restrictions in Technical Specification 6.1 and Procedure 5ACD 6.1, Revision 13. Both documents required plant manager authorization to deviate from the overtime restrictions. The licensee identified five instances in which licensee personnel failed to get authorization before exceeding the overtime restrictions. One employee in the Operations Department worked more than 24 hours in a 48-hour period; one employee in the Engineering Department worked 15 consecutive days without 2 days off; and two employees in the Engineering Department and one in the Operations Department worked more than 16 hours in a 24-hour period. Only one of the five instances took place during the outage.

REQUIREMENT:

10 CFR Part 50, Appendix B, Criterion V, states, in part, that quality-related activities should be accomplished in accordance with appropriate procedures.

REFERENCE:

Administrative Control Directive 5ACD 1.5, Revision 11, "Procedure Control."
Administrative Control Directives, 5ACD 3.10, "Equipment Control"
Administrative Control Directives, 5ACD 6.1, Revision 13, "Plant Operations"
Administrative Work Instruction, Station Procedure D80, Revision 5, "Scaffolding and Ladder Construction Use"
Administrative Work Instruction, 5AWI 3.10.1, "Method of Performing Independent Verification"
Supplemental Work Instruction (SWI)-M-20, "Prairie Island Maintenance Work Practice and Work Practice Standard"
Abnormal Operating Procedure 2C20.7 AOP 1, Revision 0, "Failure of D5 or D6 Keep Warm System."
C20.5-1, Revision 4, "4.16-kV Breaker Rack In/Out"
C20.6-1, Revision 2, "480-V Breaker In/Out"
2C20.7, Revision 0, "D5/D6 Diesel Generators"
Operating Committee Procedure EP17-41, "Maintenance of Prairie Island Allis Chalmers 480 Volt Breakers LA-600 Manually Operated Breakers 123 and 126"

APPENDIX B

LIST OF OBSERVATIONS

92-201-02 Availability of RHR (Section 3.1.4)

APPENDIX C

EXIT MEETING ATTENDEES

Northern States Power Company

Albrecht, K. J.	General Superintendent Engineering
Assmus, T.	Probabilistic Shutdown Safety Assessment
Fraser, R. G.	Projects, Superintendent Mechanical/Civil Engineering
Hunstad, A. A.	Staff Engineer
Lenertz, G. T.	General Superintendent Plant Maintenance
Lindsey, R.	Operations Experience Assessment
Maki, J.	Electrical Systems Superintendent
Maurer, J. M. III	Outage Schedule Specialist
McDonald, J. A.	Power Supply Quality Assurance
Phillips, W. F.	Maintenance Staff Coordinator
Reynolds, D.	Training
Ryan, P. C.	Shift Manager
Sellman, M. B.	Plant Manager
Sorensen, J.P.	Plant Scheduling and Services Supervisor
Wadley, M. D.	General Superintendent Plant Operations
Watzl, E. L.	Site General Manager

Nuclear Regulatory Commission

Burgess, B. L.	Section Chief, Region III
Dapas, M. L.	Senior Resident Inspector, Region III
Gamberoni, M. K.	Project Manager, NRR
Hsia, A. H.	Project Manager, NRR
Imbro, E. V.	Branch Chief, NRR
Koltay, P. S.	Team Leader, Phase 2, NRR
Kosloff, D.	Resident Inspector, Region III
Jenkins, R. V.	Electrical Engineer, NRR
Lennartz, J. A.	Examiner, Region III
O'Brien, K.	Resident Inspector, Region III
Pohida, M. A.*	Engineer, NRR
Sanchez, S. P.	General Engineer, NRR
Shafer, W. D.	Branch Chief, Region III
Skinner, C.	General Engineer, NRR
Wang, Hai-Boh*	Engineer, NRR
Westburg, R. A.*	Team Leader, Region III
Wilcox, Jr., J. D.	Team Leader, Phase 1, NRR

*Did not attend exit meeting

APPENDIX D

ABBREVIATIONS

ACD	administrative control directive
AEO	assistant equipment operator
AOP	abnormal operating procedure
AWI	administrative work instruction
CC	component cooling
CFR	Code of Federal Regulation
EDG	emergency diesel generator
EOP	emergency operating procedure
ESF	engineered safety feature
INPO	Institute of Nuclear Power Operations
I&R	isolation and restoration
IV	independent verification
kV	kilovolt
MCC	motor control center
NRC	U.S. Nuclear Regulatory Commission
NSP	Northern States Power Company
NUMARC	Nuclear Management and Resources Council, Inc.
OC	operations committee
OPT	outage planning team
OSS	outage scheduling specialist
PI	Prairie Island
PINGP	Prairie Island Nuclear Generating Plant
PRA	probabilistic risk assessment
RCS	reactor coolant system
RHR	residual heat removal
RWST	refueling water storage tank
SBO	station blackout
SG	steam generator
SSA	shutdown safety assessment team
SWI	supplemental work instruction
TI	temporary instruction
TS	technical specification
TSI	technical specification interpretation
V	volt
WCC	work control center
WR	work request