U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Docket Nos: | 50-282, 50-306 |
| License Nos: | DPR-42, DPR-60 |
| Report No: | 50-282/99004(DRP); 50-306/99004(DRP) |
| Licensee: | Northern States Power Company |
| Facility: | Prairie Island Nuclear Generating Plant |
| Location: | 1717 Wakonade Drive East<br>Welch, MN 55089 |
| Dates: | April 7 through May 31, 1999 |
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## EXECUTIVE SUMMARY

Prairie Island Nuclear Generating Plant, Units 1 & 2
NRC Inspection Report 50-282/99004(DRP); 50-306/99004(DRP)

This inspection was performed by the resident and regional inspectors and others and included aspects of licensee operations, maintenance, engineering, and plant support. Temporary Instruction (TI) 2515/141, "Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants," was completed during this inspection. The NRC staff reviewed a potential enforcement issue associated with design control of auxiliary building doors.

### Operations

- All of the operating activities observed by the inspectors were accomplished well. Several examples demonstrated good operator alertness. Good communications practices and self-checking were also observed. (Section O1.1)

- The inspectors identified that a Unit 1 containment Sump C hatch blocking bolt was not in the position required by an attached safeguards hold tag. The problem was caused by personnel errors by the shift supervisor and a radiation protection specialist. The mispositioning was not significant for the existing plant conditions, and the finding was considered a non-cited violation. (Section O1.1)

- The operators' performance during reactor shutdown, cooldown, and reactor coolant system draining evolutions was good. Proper use was made of procedures, communications were formal, and turnovers were thorough. (Section O1.2)

- The inspectors reviewed reduced inventory equipment status and lineups associated with reactor coolant system level at the top of the hot legs and found only one minor discrepancy. (Section O1.3)

- The pre-evolution briefing for fuel assembly transport from the core to the spent fuel pool was detailed and informative. The fuel assembly moves were conducted in a controlled manner. No deficiencies were identified. (Section O1.4)

- The surveillance test procedure upgrade project was properly expanded and was making adequate progress towards improving procedure quality. Initiation of a work order quality group had a positive effect in reducing the number of work order temporary change notices. The licensee implemented administrative work instructions which clearly defined management expectations concerning procedure level-of-use requirements. Steady progress was being made in reducing the number of backlogged procedure change requests. Licensee efforts to characterize the backlog indicated that the large majority of the open procedure change requests involved procedure enhancements and did not affect operating, equipment, or personnel safety. (Section O3.1)

### Maintenance

- All of the 14 maintenance and surveillance test activities observed by the inspectors were performed well. Procedure use and adherence was proper. Control of personnel and communications was good. System engineers were frequently observed to be actively involved with the maintenance and surveillance test activities associated with their systems. The inspectors identified one minor procedure format problem and one isolation card that had become detached from the valve it controlled. (Section M1.1)

- The integrated safety injection with simulated loss of offsite power surveillance test activity was performed properly with one exception. The licensee identified that the wrong manual switch was used to initiate the safety injection on May 19, 1999, and previously on December 6, 1997. Although incorrect, the switch testing performed at the completion of the last two outages did meet the Technical Specifications requirements of staggering the switch testing. However, the test completed in December 1997 did not meet the Technical Specifications requirement for staggering the switches and was considered a non-cited violation. (Section M1.3)

- The material condition of the safety injection accumulator and residual heat removal components in the Unit 1 containment was adequate. No discrepancies were noted in labeling and configuration control of the system components. (Section M2.1)

Engineering

- Limitations associated with 22 examinations of the Unit 2, 3rd 10-year inservice inspection components were adequately documented and American Society of Mechanical Engineers Section XI code reliefs appropriately requested. New volumetric indications associated with steam generator tubesheet-to-head and tubesheet-to-shell welds were properly dispositioned as manufacturing, non-service induced flaws. Minor, attention-to-detail errors were noted in the review of ultrasonic scan examination records but they did not affect the overall inspections or conclusions of component operability. (Section E3.1)

- The licensee identified that it had modified three auxiliary building doors early in plant life and had failed to identify at the time that the modified doors no longer met their design basis for pressure relief after a high-energy line break. Enforcement discretion was exercised and the finding was considered a non-cited violation. (Section E8.1)

Plant Support

- Following refueling activities, the licensee identified hot particles in the Unit 1 reactor cavity sump, the highest of which read 600 R/hr on contact. Radiation protection personnel responded appropriately and took sufficient time to consider all options for removing the hot particles from the reactor cavity sump. The hot particles were removed in a controlled and deliberate manner with a remotely operated tool and under close health physics supervision. Total dose for removing the hot particles from the cavity sump was 182 mrem which reflected a plan that was devised and executed well. (Section R1.1)

## Report Details

Summary of Plant Status

Unit 1 operated continuously at or near full power until April 16 - 17, 1999, when the Unit shut down for a scheduled refueling outage. Unit 1 returned to full power operation on May 29, 1999. Unit 2 operated at or near full power for the entire inspection period.

## I. Operations

### O1 Conduct of Operations

O1.1 General Comments

a. Inspection Scope (71707)

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

b. Observations and Findings

- On April 13, 1999, the inspectors observed from the control room the cycling of safety injection (SI) pump boric acid tank supply motor valves in accordance with Step 7.2 of Surveillance Test Procedure (SP) 1088, "Safety Injection Pumps Test," Revision 40. The reactor operator performing the test used good self-checking techniques during valve cycling and timing checks. The operator read the procedure that identified the valve to be cycled, pointed to the control switch of the valve to be cycled, verifying that it matched the procedure instructions, reread the procedure step an additional time, and then manipulated the valve. The inspectors observed good reactor operator control of the evolution when communications with the local operator in the auxiliary building via hand-held radio became difficult. The reactor operator stopped the test, paged the local operator on the site announcing system, and reestablished contact via the normal telephone system. The reactor operator instructed the local operator to use a sound-powered phone headset for the rest of the evolution. The surveillance test was subsequently completed with no further communication problems.

- The inspectors observed the D6 emergency diesel generator surveillance test performed in accordance with SP 2305, "D6 Generator Slow Start Test," Revision 9. After the generator had achieved 100 percent load, the inspectors performed a walkdown of the two diesel engines and the associated engine auxiliaries, instrumentation, and safeguards switchgear. Two discrepancies were found. First, the inspectors noted that the closed indicating light on the safeguards bus cubicle for the D6 output breaker was not lit, even though the breaker was closed. Second, D6 engine 1 inboard turbocharger exhaust temperature instrument 60026 was failed down-scale low.

Shortly thereafter, the turbine building operators began taking the first set of D6 log readings in accordance with SP 2305, Step 7.42. The operators immediately noticed the failed turbocharger exhaust temperature instrument, recorded the failed instrument in the SP, and later coordinated with the system engineer to write Work Order (WO) 9904813 for repair. The inspectors discussed the failed D6 output breaker indicating light with one of the operators who stated that he had already noted the problem and was in the process of replacing the burned out light bulb. The operators demonstrated a good awareness of equipment status by promptly noting a failed turbocharger exhaust temperature indication and a lack of local breaker position indication for the diesel generator output breaker.

- On April 13, 1999, the control room received an unexpected seismic event annunciator. Operators appropriately followed Alarm Response Procedure C47023-0606, "Seismic Event," Revision 23, and referenced Abnormal Procedure (AB)-3, "Earthquakes," Revision 15. The operators closely monitored safeguards cooling water intake bay level for evidence of blockage per AB-3, Step 2.4.1, and evaluated the earthquake severity in accordance with AB-3, Attachment A. The operators also demonstrated sensitivity to spent fuel cask issues after the alarm. Cask 09 was being moved from the refueling building to the independent spent fuel storage installation that day. The operators verified that Cask 09 had been landed at its final location and was no longer in transit.

  A licensee investigation into the seismic event annunciator under WO 9904829 revealed that the alarm was spurious and most likely caused by work activities occurring adjacent to a seismic detector. The inspectors reviewed the strip charts associated with the annunciator and verified that no vibratory ground motion had actually occurred. The inspectors noted that the shift manager contacted the National Earthquake Information Center in Boulder, Colorado to confirm that no seismic activity had taken place in the region.

  One of the considerations in granting License Amendments 131 and 140 dated November 4, 1998, was the use of manual operator actions to reduce cooling water loads, in accordance with AB-3, following a seismic event. The seismic event annunciator that occurred on April 13 demonstrated the control room operators' ability to properly respond to an unexpected seismic event as assumed in the license amendment.

  Two other seismic alarms occurred on April 23 and May 5, 1999. The licensee investigated the alarms under WO 9905012 and found two deficiencies associated with a horizontal trigger on one of the detectors. First, the trigger was observed to be off-center and touching a sensor rim, causing spurious signals as the trigger occasionally moved. Second, the bolt rigidly attaching the trigger to the auxiliary building structure had become loose. The findings were documented in Nonconformance Report (NCR) 19991640. Corrective actions included installing a new mounting bolt and submitting Procedure Change Request (PCR) 19990804 to add steps to the appropriate SP to check for similar problems during future calibrations.

- On April 19, 1999, the inspectors noted that the number 11 reactor cavity Sump C hatch Safeguards Hold Tag 1-198, "Sump C Access Hatch Swing Bolts

Blocking Closure," was still attached to the blocking bolt, but the bolt had been mispositioned and was no longer blocking the access hatch in the open position. The inspectors were concerned that a component with safeguards implications had been changed to a position contrary to that required by the tag while the tag was still attached. The inspectors brought the finding to the attention of the Unit 1 shift supervisor who had the safeguards hold tag removed, since plant conditions (refueling outage) no longer required Sump C access hatches to be locked in the open position.

Earlier that same day, the Unit 1 shift supervisor signed out the Sump C access hatch key to a licensee radiation protection specialist so that air samples could be taken in the sump prior to personnel access. The licensee radiation protection specialist gave the key to a contractor radiation protection specialist who unlocked and mispositioned the blocking bolt while completing the air samples. The contractor failed to notice the instructions on Safeguards Hold Tag 1-198 while taking the air samples. The Unit 1 shift supervisor did not realize that the sump hatch had a safeguards hold tag attached when he gave the access key to the licensee radiation protection specialist.

Applicable procedural requirements controlling safeguards hold tags included:

- Administrative Work Instruction (AWI) 5AWI 3.10.0, "Control and Operation of Plant Equipment," Revision 8, Step 6.6.2, which stated, "The operating status of locked or blocked equipment shall be changed only when authorized by the SS [shift supervisor]";

- 5AWI 3.10.0, Step 6.6.3, which stated, "Positioning of locked or blocked components for safety and/or operating considerations shall be per SWI [Section Work Instruction] O-3 and the applicable requirements of this instruction";

- SWI 0-3, "Safeguards Hold and Component Blocking or Locking," Revision 55, Step 6.1, which stated, "A lock or block shall not be removed except by the Shift Supervisor's permission";

- SWI 0-3, Step 6.6 which stated, "The installation and removal of Safeguards Hold Tags shall be logged in Table 1." Table 1 was titled, "Component Blocking and Locking Log";

- Unit 1 Severe Accident Management Guidelines 1SAG-4, "Inject Into Containment," Basis for Actions in 1SAG-4, Procedure Steps, Step 4, Note 1, discussed containment and reactor cavity design features that facilitated flooding of the reactor cavity. Credit was taken for containment water flowing through the two locked-open Sump C access hatches into the reactor cavity instrument tunnel to provide external cooling for the reactor vessel lower head; and

- Unit 1 Severe Accident Management Computation Aids, Section 1CA-5, "Unit 1 Containment Water Level and Volume," Figure 1CA-5-1, assumed that the Sump C access hatches were open and that at an indicated level of approximately 6.25 feet in containment, the lower head of the reactor vessel would be submerged.

The licensee convened an error reduction task force (ERTF) investigation (ERTF 99-05, tracking number 19991361) to review the event on April 21, 1999. The ERTF investigation had not been completed and corrective actions not formally defined by the end of this inspection period. The inspectors noted that SWI 0-3 was considered a procedure affecting quality in that it provided configuration control of components involving nuclear safety.

The inspectors discussed severe accident management guideline assumptions with a training instructor who was one of the writers of the guidelines. The inspectors learned that one of the assumptions of the guidelines was that the Sump C access hatches were locked open to provide external lower reactor vessel head cooling during severe events. The guidelines assumed, however, that the severe accident began from full power conditions. In this case, the safety significance of the inspectors' finding was low since the condition was discovered approximately 80 hours after Unit 1 had been shutdown for a refueling outage. At that point the reactor decay heat generation rate was substantially lower than full power conditions. The Sump C access hatch had been mispositioned approximately 70 hours after Unit 1 shutdown. The inspectors determined that the licensee would probably have identified the error prior to Unit 1 restart since Operating Procedure 1C1.2, "Unit 1 Startup Procedure," Revision 20, Step 5.1.7.L, contained a requirement for the containment system engineer to complete SP 1750, "Post Outage Containment Close-Out Inspection," Revision 16, prior to restart. The instructions in Step 7.3.14 of SP 1750 specifically required the system engineer to verify that the Sump C access hatches were locked with a chain and blocked partially open.

Technical Specification (TS) 6.5.A. required that integrated and system procedures for normal reactor startup, operation, and shutdown of the reactor and all systems and components involving nuclear safety of the facility be prepared and followed. Contrary to the requirements of TS 6.5.A, the licensee failed to control the position, status, and logging of Safeguards Hold Tag 1-198, "Sump C Access Hatch Swing Bolts Blocking Closure," in accordance with procedure SWI 0-3, Steps 6.1 and 6.6. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. (NCV 50-282/99004-01(DRP)) This violation is in the licensee's corrective action program under tracking numbers ERTF 99-05 and 19991361.

c. <u>Conclusions</u>

All of the operating activities observed by the inspectors were accomplished well. Several examples demonstrated good operator alertness. Good communications practices and self-checking were also observed. The inspectors identified a component that was not in the position required by an attached safeguards hold tag. The problem was caused by shift supervisor and radiation protection specialist personal errors. The mispositioning was not significant for the existing plant conditions, and the finding was considered an NCV.

## O1.2 Unit 1 Shutdown and Transition Into Refueling Outage

### a. Inspection Scope (71707)

The inspectors observed a Unit 1 shutdown on April 16 - 17, 1999, for a scheduled refueling outage. The inspectors observed the transition from full power operation to off-line conditions, number 11 and 12 reactor coolant pump (RCP) vibrational testing, portions of the reactor coolant system (RCS) cooldown, transition into residual heat removal (RHR) cooling, and portions of the drain down to reduced RCS inventory conditions. Reference material used during this inspection included:

- Operating Procedure 1C1.4, "Unit 1 Power Operation," Revision 17;
- Operating Procedure 1C1.3, "Unit 1 Shutdown," Revision 42;
- Operating Procedure 1C1.6, "Shutdown Operations - Unit 1," Revision 9;
- Operating Procedure C3, "Reactor Coolant Pump," Revision 23;
- 5AWI 1.5.9, "Procedures - Level of Use," Revision 1;
- SWI O-25, "Periodic Data Acquisition and Log Keeping," Revision 22;
- Special Operations Procedure 1D2, "RCS Reduced Inventory Operation," Revision 8; and
- Work Order 9902038, "Take Vibrational Data on 11 and 12 RCPs."

### b. Observations and Findings

The operators conducted the refueling outage shutdown with no discrepancies. All equipment operated as expected and communications remained formal and adequate. The inspectors noted that the reactor operator remained attentive to reactor parameters and adequately controlled average reactor coolant temperature, reactor power, and axial flux distribution throughout the shutdown. The lead reactor operator maintained good control over newly qualified operators by instructing them to walkdown systems and components before system manipulations were required. This ensured that newly qualified operators were able to perform procedural actions in a timely and efficient manner when required. An extra lead reactor operator and reactor operator were assigned to the Unit 1 control room crew to assist in shutdown duties. The inspectors noted that the extra lead reactor operator used good communication practices and maintained good control of operators while restoring substation configuration following the opening of the main generator output breakers.

Operating Procedures 1C1.3 and 1C1.4 were designated as continuous use procedures in accordance with administrative procedure 5AWI 1.5.9. During the shutdown, the inspectors noticed that the continuous use procedure requirements of 5AWI 1.5.9 were met. Namely, each step was read before performance, steps were marked off as completed, and the procedures were open and available in the control room. The inspectors independently verified the reactor operator's cold shutdown boron concentration calculations and found no discrepancies.

The inspectors observed vibrational testing of the number 11 and 12 RCPs in accordance with WO 9902038. Pump coast down, startup, and operating vibration data was collected because of a slight increase in the number 12 RCP vibrations that had been noted over the last fuel cycle. The inspectors noted good coordination between the RCP system engineer, vendor consultant, and the control room operators. The inspectors verified that the number 11and 12 RCPs were properly cycled in accordance with Operating Procedure C3, Steps 5.1 and 5.3.

The inspectors observed the transition from intermediate shutdown mode/cold shutdown mode and the initiation of RHR cooling. Positive verification of the heat removal capability of the RHR system was made prior to shutting the main steam isolation valves and securing steam dumping capabilities.

The inspectors observed a control room crew turnover which occurred just prior to initiating a plant cooldown using RHR. The inspectors noted that the individual turnovers of the operators were very detailed and included complete, simultaneous control board walkdowns, discussions of out-of-service equipment, a review of the status of operating procedures being used, and discussions of the overall status of the reactor and secondary plant.

On April 19, 1999, the inspectors observed the draining of the Unit 1 RCS from 30 percent level in the pressurizer to one foot below the reactor vessel flange. The evolution was conducted in accordance with Operating Procedure 1C4.1, Step 5.2, and observed in both the control room and containment. The inspectors verified that the RCS was properly vented during the draining evolution by walking down the reactor head vent and the pressurizer to pressurizer relief tank lineups. Where openings to the RCS existed, the inspectors verified that adequate controls were in place to prevent entry of foreign material into the primary system. The inspectors also walked down the tygon tube standpipe level indication and verified that the RCS isolation valves to the standpipe were open, that the tube contained no kinks or loop seals, and that an open vent path existed at the top of the standpipe. During the draindown, the inspectors verified that operators were properly located in containment at the reactor vessel head vent, the tygon tube standpipe, and in the control room to control the draining evolution. Communications remained formal and the evolution was completed without problems.

Draining from one foot below the reactor vessel flange to the top of the hot legs in accordance with Special Operations Procedure 1D2, Step 5.2, was conducted on April 19 -20, 1999. The draining evolution was conducted normally without problems until the reactor coolant drain tank pump stopped automatically in accordance with 1D2, Step 5.2.30. After the reactor coolant drain tank pump stopped, the RCS level continued to drop slowly. After about 15 minutes, the control room operators started the number 12 charging pump to maintain RCS level at the top of the hot leg. The operators were concerned that if RCS level continued to drop, the RHR pumps might loose suction, causing a loss of shutdown cooling. Available operators and health physics technicians inspected the RCS piping in containment and the auxiliary building looking for RCS leaks. No leaks were found. The lowest RCS level reached was 724 feet 1 inch which was 4 inches below the minimum RCS hot leg level specified in 1D2, Step 5.2.30.D. That level resulted in the hot leg piping being approximately 3/4 full, but did not cause cavitation of the running RHR pump or loss of shutdown cooling.

The physical configuration of the RCS drain piping provided a self-limiting effect which would have prevented a loss of shutdown cooling by preventing the hot leg level from dropping below the hot leg centerline, 723 feet 4 ¼ inches. Thus, the lowest level reached in the hot leg was approximately 9 inches above the point at which the self-limiting drain would have come into effect. The licensee documented the event in NCR 19991384 and initiated ERTF 99-07 to review the draindown. The ERTF investigation had not been completed or corrective actions formally defined by the end of this inspection period. The preliminary indications were that the problem may have been due to inadequate venting of the RCS during the draining. The licensee quarantined Special Operations Procedures 1D2 and 2D2 (Procedure Quarantine Forms 1999-0011 and 1999-0012) until the ERTF investigation was complete.

c. Conclusions

The operators' performance during reactor shutdown, cooldown, and RCS draining evolutions was good. Proper use was made of procedures, communications were formal, and turnovers were thorough. The licensee was evaluating a problem where the RCS level continued to drop slowly after the RCS draining evolution was stopped.

O1.3 Review of Reduced Inventory Operations

a. Inspection Scope (71707)

On May 11, 1999, the inspectors observed portions of the second period of reduced RCS inventory operations on Unit 1. The RCS was drained to the top of the hot legs to facilitate removal of nozzle dams following completion of steam generator eddy current inspections. The inspectors utilized the following documents as part of this inspection:

- Special Operations Procedure 1D2.1, "RCS Reduced Inventory Operation After Pool Flood," Revision 8; and

- Operating Procedure C19.9, "Containment Boundary Control During Cold Shutdown and Refueling Shutdown," Revision 5.

b. Observations and Findings

The inspectors performed walkdowns of the RHR system in the control room, auxiliary building, and containment to verify that the appropriate shutdown cooling paths were in place. The inspectors also examined all safety-related 4160- and 480-volt switchgear lineups associated with reduced inventory conditions. In the Unit 1 containment, the inspectors reviewed RCS vent paths and reactor vessel standpipe level indication lineups. Control room equipment lineups associated with the refueling water storage tanks and charging systems were also reviewed by the inspectors. No discrepancies were noted during any of the walkdowns, and the RHR and charging systems were determined to have been fully operable.

The inspectors reviewed and walked down safety-related isolations associated with reduced inventory operations for the volume control, RHR suction, and reactor vessel standpipe level indication systems. All components were in the proper position with correctly attached and independently verified secure (equipment isolation) cards. The Alternate Isolation and Containment Boundary Opening Log was used to control refueling and containment integrity boundaries during the refueling outage in accordance with C19.9. The inspectors reviewed the log and found it to be up-to-date and accurate for plant conditions. High-flux-at-shutdown alarms were lined up in the proper state. Flammable transient combustible loading was acceptable in all areas observed by the inspectors.

The inspectors observed a Unit 1 control room crew turnover on May 14, 1999. At the time Unit 1 was in reduced inventory conditions with RCS level at the top of the hot legs. During the turnover, the oncoming and offgoing lead and reactor operators performed control board walkdowns and reviewed logs and active work status. Preparations and plans for filling the RCS to one foot below the reactor vessel flange on the upcoming shift were discussed in detail. The turnovers observed by the inspectors were adequate and communicated plant conditions to the oncoming crew.

The inspectors reviewed the posting of reduced inventory signs in accordance with 1D2.1, Step 5.1.8, Table 4. Two different types of signs were used to remind personnel that the RCS was in reduced inventory conditions and that shift supervisor permission was required prior to manipulating any equipment that could affect reduced inventory operations. The inspectors noted that the sign posted on the front of the 1RYBT and 1RY POT panels in the bus 13/14 room and on the front of the 12RYBT and 2R panels in the bus 23/24 room did not explicitly match the sign required in 1D2.1, Table 4, Step 2. Rather, the sign described in 1D2.1, Table 4, Step 3, was used. This observation was of low safety significance since both types of signs, although containing slightly different messages, stated that the RCS was in reduced inventory conditions and that shift supervisor permission was required prior to manipulating any components.

c. Conclusions

The inspectors reviewed reduced inventory equipment status and lineups associated with RCS level at the top of the hot legs and found no discrepancies. Minor attention-to-detail errors were noted concerning the posting of reduced inventory signs on electrical switchgear.

## O1.4 Fuel Handling Operations

a. Inspection Scope (71707)

During the Unit 1 refueling outage, a full core offload was conducted to facilitate reactor vessel thimble tube replacement. The inspectors observed work activities associated with the removal of fuel assemblies from the reactor core and transport to the spent fuel pool. Later the inspectors observed portions of the core reload activities. Included as part of this review were the following documents:

- Special Operating Procedure D5.2, "Reactor Refueling Operations," Revision 24;
- Operating Procedure C17, "Fuel Handling System," Revision 26;
- SWI O-41, "Duties and Responsibilities of Fuel Handling Personnel," Revision 6; and
- Technical Specification Section 3.8, "Refueling and Fuel Handling."

b. Observations and Findings

The inspectors attended a pre-evolution briefing for the transport of fuel assemblies from the reactor core to the spent fuel pool. The briefing was conducted by a nuclear engineer. Attendees included operators, engineers, radiation protection personnel, quality services personnel, and licensee management representatives. The briefing was detailed and included a discussion of individual responsibilities, communications, precautions, and past problems. The briefing leader stressed the need to do things slowly and correctly the first time.

The inspectors observed the transport of fuel assemblies from the reactor core to the spent fuel pool from the control room, containment, and spent fuel pool area. Applicable procedures were out and in active use in all three locations. The fuel assembly moves were conducted in a controlled manner, with proper oversight by senior reactor operators and appropriate system engineer oversight. The licensee used three-part communications in accordance with station procedures. The phonetic alphabet was not used in all cases, however, use of the phonetic alphabet was not a management expectation and the inspectors did not identify any errors.

The inspectors noted that fuel transfer logs and the fuel handling status board were used successfully in tracking and recording the location of each fuel assembly being moved. Positive multiple-person verification techniques were utilized prior to a fuel assembly being removed or installed from a given location.

c. Conclusions

The pre-evolution briefing for fuel assembly transport from the core to the spent fuel pool was detailed and informative. The fuel assembly moves were conducted in a controlled manner. No deficiencies were identified.

**O2 Operational Status of Facilities and Equipment**

O2.1 Walkdown of Safety-Related System

a. Inspection Scope (71707)

The inspectors performed a walkdown of safety-related 125-volt direct current (DC) distribution panels in the Unit 1 containment during the refueling outage. References used included:

- USAR Section 8.5, "DC Power Supply Systems," Revision 14;
- Drawing NF-40171-3, "Wiring Diagrams Power Penetrations C1, C4, C5, C9," Revision K;
- Drawing NF-40171-4, "Wiring Diagram - Power Penetrations D1, D2, D3, D5, D6, D9, D10, D11 & D12," Revision V;
- Drawing NF-40301-1, "Wiring Diagram DC Distribution Panels "A" Train," Revision BC;

- Drawing NF-40301-2, "Wiring Diagram DC Distribution Panels "B" Train," Revision AT;

- Drawing NF-40301-3, "External Wiring Diagram DC Distribution Panels 151, 152 & 153 (Train "A")," Revision AS; and

- Drawing NF-40301-4, "External Wiring Diagram DC Distribution Panels 161, 162 & 163 (Train "B")," Revision U.

b. Observations and Findings

The inspectors used the drawings and the controlled placards located on the inside of the door of each distribution panel to verify that 125-volt DC distribution configuration in Unit 1 containment was properly controlled and maintained for the existing plant conditions. No discrepancies were noted.

c. Conclusions

The 125-volt DC system in the Unit 1 containment was properly lined up for the existing mode of operation.

**O3 Operations Procedures and Documentation**

O3.1 Review of Procedure Process Improvement Initiatives

a. Inspection Scope (92901)

The most recent System Assessment of Licensee Performance Report (50-282/98001; 50-306/98001) identified weaknesses in the area of procedure adequacy and quality which were caused, in part, by a lack of clearly established and enforced management standards for the development, review, and approval of procedures and procedure revisions. The inspectors interviewed the procedure upgrade project manager and reviewed procedure trend data and the progress made in improving procedure quality since early 1998.

b. Observations and Findings

Based on an initial SP pilot project review in 1998, the licensee decided to enlarge the SP upgrade project to include approximately 600 of the 900 SPs. The 600 SPs selected for review were predominantly operations department surveillance tests. Approximately 15 months after the beginning of the project, 79 SP reviews had been completed with another 138 SPs in the active review cycle. The reviews completed, as of April 1999, had identified needed improvements in application of the writer's guide to improve the SP clarity and in clearly defining surveillance test acceptance criteria. The complete SP upgrade project was expected to take approximately 3.5 years and was scheduled to be complete in 2001. The progress to date was on schedule, and the inspectors noted that few recent observations had found procedural adequacy and quality problems.

Work order (WO) quality improvement initiatives were also begun in October 1998. Initiatives included forming a WO quality group consisting of the procedure upgrade project manager, outage management supervisor, superintendents of electrical, mechanical, and instrumentation and control systems engineering, a shift supervisor, and a superintendent of mechanical/electrical maintenance. The objective was to align diverse system engineer writing styles and abilities to gain consistency and improvements in WO format, style, and equipment isolation instructions. The inspectors reviewed procedure trend data and noted that the percentage of WOs requiring temporary change notices (TCNs) had declined from a peak of approximately 35 percent in November 1998, to 11% in March 1999. During the Unit 1 refueling outage in April 1999, 17% of the WOs required TCNs. This was compared to 26% of the WOs requiring TCNs during the last Unit 2 outage period in November 1998. This demonstrated an improving trend in WO quality during normal operations and outage periods.

The licensee implemented administrative procedure 5AWI 1.5.9, "Procedures - Level of Use," Revision 1, on March 16, 1999. In the AWI, the licensee defined continuous, reference, information, and multiple level of use categories that were assigned to all of the approximately 4200 licensee written procedures. The level of use classifications defined in 5AWI 1.5.9 were also extended to all WOs. During the inspection period, the inspectors noted that all procedures and WOs used by operations, engineering, maintenance, and plant support personnel and reviewed by the inspectors contained the appropriate level of use classifications.

The inspectors reviewed the licensee procedure change request (PCR) backlog and noted that as of April 1999, there were approximately 900 open PCR submittals. This backlog had been reduced from a peak of 1300 PCRs in February 1999, but had remained above 1000 PCRs since June 1998. In order to better understand the importance of the backlog, the licensee prioritized each of the PCRs into one of three categories. Priority 1 included those PCRs affecting safety or that could prevent restart following refueling activities. Priority 2 included those PCRs considered enhancements or that were likely to prevent incidents. Priority 3 included editorial changes and minor procedure enhancements. As of April 15, 1999, approximately 50 percent of the PCRs had been prioritized. Sixty-five percent were categorized as priority 3 and 35 percent as priority 2. Two PCRs had been categorized as priority 1 and were being properly addressed by the licensee. The PCRs reviewed by the inspectors were appropriately prioritized. The PCR categorization process was expected to be complete by the end of May 1999.

The licensee was also coordinating with a vendor to identify and improve process weaknesses in the AWI procedures. The AWI upgrade project was in the early stages of development and included improvements in the work control, temporary change notice, and equipment isolation and restoration processes. The goal was to improve AWI adherence by more clearly defining and communicating process requirements.

c. <u>Conclusions</u>

Satisfactory procedure improvement initiatives have been taken by the licensee in the SP, WO, procedure level-of-use requirements, and PCR backlog areas. The SP upgrade project was properly expanded and was making adequate progress towards improving procedure quality. Initiation of a WO quality group had a positive effect in reducing the number of WO TCNs. The licensee implemented AWIs which clearly defined management expectations concerning procedure level-of-use requirements. Steady progress was being made in reducing the number of backlogged PCRs.

Licensee efforts to characterize the backlog indicated that the large majority of the open PCRs concerned procedure enhancements and did not affect operating, equipment, or personnel safety.

**O7 Quality Assurance In Operations**

O7.1 Safety Audit Committee (SAC) Meeting

a. Inspection Scope (71707)

On April 8, 1999, the licensee held its semi-annual SAC meeting as required by TS 6.2.A. The inspectors observed portions of the meeting.

b. Observations and Findings

The inspectors verified that the membership, qualification, and quorum requirements of TS 6.2.A were met. The inspectors observed portions of the SAC meeting and noted that some of the items discussed by the SAC members included:

- plant performance trends, quality services audit findings, and upcoming audit schedules;
- status of procedure adherence and quality improvement initiatives;
- significant plant events since the last SAC meeting; and
- status of and needed improvements in the corrective action program, including more detailed analysis of error reduction task force cause codes.

c. Conclusions

Activities of the SAC observed by the inspectors met the requirements of the TS.

## II. Maintenance

**M1 Conduct of Maintenance**

M1.1 General Comments

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

The inspectors observed all or portions of several maintenance and surveillance test activities. Included in the inspection was a review of the SPs and WOs listed, as well as the appropriate USAR sections regarding the activities. The inspectors verified that the SPs for the activities observed met the requirements of the TSs. The following activities and procedures were reviewed by the inspectors:

- SP 1088, "Safety Injection Pumps Test," Revision 40;

- SP 1102, "11 Turbine-Driven AFW [Auxiliary Feedwater] Pump Monthly Test," Revision 65;

- SP 2102, "22 Turbine-Driven AFW Pump Monthly Test," Revision 57;

- SP 1713, "SI [Safety Injection] Mini Recirc Line Flowmeter Annual Functional Test," Revision 5;

- SP 2088, "Safety Injection Pumps Test," Revision 39;

- SP 2305, "D6 Generator Slow Start Test," Revision 9;

- SP 1750, "Post Outage Containment Close-Out Inspection," Revision 16;

- WO 9803499, "12 Motor-driven AFW Pump Motor Bearing Leaking Oil";

- WO 9901558, "CV-31506 is Leaking Past Seat When Closed";

- WO 9902055, "Swap Two D6 Injector Pumps";

- WO 9902569, "Quarterly Shaft Speed/Vibration/Valve Exercise";

- WO 9902376, "Quarterly Shaft Speed/Vibration/Valve Exercise";

- WO 9904829, "Seismic Event In The Auxiliary Building"; and

- WO 9905012, "Seismic Event In The Auxiliary Building."

b. Observations and Findings

- The inspectors observed portions of SP 1088 on April 13, 1999. The inspectors noted that the SI boric acid tank supply motor valves cycled within the prescribed time limits. Both the number 11 and 12 SI pumps operated within normal temperature, pressure, and flow parameters during Sections 7.3 and 7.4 of the test. The inspectors verified that vibration measuring equipment was in calibration and that all motor and pump vibration measurements fell within normal ranges. Auxiliary building operators were attentive to the SI pumps while running and maintained good control of two trainees observing the test. The system engineer was present throughout the surveillance test and performed frequent, independent checks of the equipment operating condition and parameters.

  In coordination with SP 1088, the inspectors observed instrumentation and controls personnel performing the annual test of the number 11 and 12 SI pump recirculation line flowmeter in accordance with SP 1713. The inspectors noted good coordination between maintenance personnel and local and control room operators during testing of the recirculation low flow annunciator.

  For both SP 1088 and 1713, the SPs were designated as continuous use procedures in accordance with AWI 1.5.9. The inspectors noted that SP 1088 and 1713 were present at the work location, steps were marked off as completed, and that each step was read prior to performance. No discrepancies were noted.

- The inspectors observed cycling of the Unit 2 SI pump refueling water storage tank supply and boric acid tank supply motor valves in accordance with Sections 7.1 and 7.2 of SP 2088. The inspectors noted formal, three-part communication practices between control room and local operators in the auxiliary building. The inspectors verified that TS Limiting Conditions for Operation entries were properly tracked, maintained, and controlled by the Unit 2 shift supervisor. All motor-operated valves cycled smoothly and all valve cycle times fell within acceptable ranges. No discrepancies were noted.

- On April 12, 1999, the inspectors reviewed the isolation associated with WO 9902055 and observed the subsequent post-maintenance surveillance test, SP 2305. The WO contained instructions for swapping two diesel engine fuel oil injectors on diesel D6, engine 2, cylinders B1 and B5, as part of an investigation into elevated cylinder exhaust temperatures. The inspectors discussed the elevated cylinder exhaust temperatures with the system engineer who stated that although the exhaust temperatures were higher than normal, manufacturer temperature limits had not been exceeded.

  While verifying Isolation 9902055 for the work, the inspectors noted that hold card number 12, for fuel oil injector B1, was not attached to the injector isolation valve as required by the isolation instructions. The inspectors searched for the missing card and found it below the injector lines on top of a set of duplex lubricating oil strainers. The inspectors then verified that the injector valve appeared to be in the correct position and that the other eleven hold cards associated with Isolation 9902055 were properly hung with the respective components correctly positioned. After the inspectors had completed the verifications, maintenance workers returned from a break. The inspectors pointed out that hold card number 12 had become detached from the injector isolation valve. The maintenance workers promptly reattached the card. A maintenance worker stated that the card had probably fallen off the isolation valve while they were removing a short section of line leading from the fuel oil supply header to the engine 2, B1 unit injector during injector swapping.

  The safety significance of the detached tag on D6 emergency diesel generator was low since no actual valves or components were mispositioned and the engine could not have started.

- The inspectors observed the monthly tests of the number 11 and 12 turbine-driven AFW pumps in accordance with SP 1102 and SP 2102. The inspectors noted that for both surveillance tests, the local operator maintained good communications with the control room and adequately supervised trainees observing and performing parts of the test. The system engineer as the lead for the AFW system was not available for SP 1102, however, the inspectors observed that the back-up system engineer was present throughout the test to monitor pump performance. All flows, temperatures, and pressure indications were within normal ranges. All motor operated valves cycled within prescribed time limits, and all pump performance acceptance criteria were met. The inspectors verified that tachometer and vibration instruments used during both surveillance tests were calibrated and that all turbine and pump speed and vibration readings recorded in accordance with WOs 9902376 and 9902569 were within normal ranges and below defined alert levels.

The inspectors reviewed SP 1102 and SP 2102 acceptance criteria to ensure that the performance of the number 11 and 12 turbine-driven AFW pumps had not degraded and that both pumps were able to perform their safety-related functions. All acceptance criteria were met.

The inspectors also reviewed the last fifteen months of number 22 turbine-driven AFW pump performance data to ensure that pump performance was being properly monitored. No other discrepancies were noted.

- The inspectors reviewed WO 9901558 and noted that the work package was properly authorized and in active use at the job site. Applicable references, such as the valve and valve actuator technical manuals were available to the mechanics. The inspectors performed a spot check of the isolation established to accomplish the work and identified no discrepancies. Control Valve CV-31506 (D2 emergency diesel generator cooling water supply control valve) was a double seated valve. The mechanics identified that a nut on the connection between the upper and lower disc assemblies was loose, which allowed the lower disc assembly to spin. When the disc spun, it increased the distance between the upper and lower discs and resulted in the upper disc leaking by. The system engineers and mechanics believed the nut came loose due to poor design, in that the body cover was turned inboard and access was difficult due to the close proximity of other equipment. The system engineers were evaluating a long-term corrective action of reorienting the valve, which would result in easier access to the valve body internals. No discrepancies were noted.

- The inspectors reviewed WO 9803499 and noted that the work package was properly approved and in use at the job site. An equipment technical representative was at the job site and provided assistance to the licensee. The description of the problem in the WO identified leaking oil from the AFW pump motor bearing. The mechanic and the technical representative did not observe the reported leak. The only leak that they saw was from the site glass. The WO had a step to install new oil seals on the motor shaft. The mechanics noted that the new seals had larger clearance than the old seals, initiated a change to the WO, and re-installed the old seals. No discrepancies were noted.

- The inspectors reviewed the requirements of SP 1750 and performed an independent tour of the Unit 1 containment building just prior to final close-out. The inspectors briefly toured all levels of the containment building and performed spot-checks of specific items listed in SP 1750. No discrepancies were noted.

c. <u>Conclusions</u>

All of the 14 activities observed by the inspectors were performed well. Procedure use and adherence was proper. Control of personnel and communications was good. System engineers were frequently observed to be actively involved with the maintenance and surveillance test activities associated with their systems. The inspectors identified one minor procedure format problem and one isolation card that had become detached from the valve it controlled.

M1.2 Error While Installing the Reactor Upper Internals

a. Inspection Scope (92902)

On May 11, 1999, the licensee informed the NRC, in accordance with 10 CFR 50.72, that Unit 1 had been in a condition outside of the design basis while reassembling the reactor. A heavy load had been moved over the open reactor while it contained fuel and while the containment in-service purge system had been operating. The inspectors reviewed the circumstances of the event.

b. Observations and Findings

The licensee discovered that on May 8, 1999, while moving the reactor upper internals over the open reactor, they had failed to isolate the in-service purge system as required by Maintenance Procedure D58.1.6, "Reactor Upper Internals Replacement," Revision 0, Step 7.6.3. The provision in D58.1.6 was in order to meet a commitment in USAR Section 12.2.12.1.4, "Containment Polar Carne Evaluation," Revision 14, which stated, "During heavy load lifts over the open fueled reactor vessel, at least one isolation valve will be closed in each line penetrating the containment which provides a direct path from the containment atmosphere to the outside."

The potential consequences from a load drop during refueling were reported in USAR Section 14.5.1.4, "FHA [Fuel Handling Accident] Inside Containment," Revision 14. The analysis indicated that the thyroid dose at the site boundary from such an accident, with the in-service purge system operating and not automatically isolating, would be about 0.38 Rem. However, during this event, two trains of automatic isolation on high radiation, as well as two trains of manual isolation were available to isolate the ventilation system. The inspectors reviewed abnormal operating and alarm response procedures, as discussed in Section M8.1 of this report, and determined that procedures, indications, controls, and training were adequate to allow credit for manual isolation of the in-service purge system.

This issue will be reviewed further, and the risk significance will be evaluated, when the licensee issues its Licensee Event Report (LER) for the event. The licensee expected to issue LER 1-99-05 on or before June 9, 1999. The LER will be considered open when issued.

c. Conclusions

The inspectors developed preliminary information regarding the risk significance of an event in which the licensee did not isolate the containment in-service purge system when moving the reactor upper internal over the reactor core. The significance determination will be completed after the licensee's LER is issued. No conclusions were reached.

M1.3 Unit 1 Integrated SI Test

a. Inspection Scope (61726)

The inspectors observed the performance of testing accomplished in accordance with SP 1083, "Unit 1 Integrated SI Test With a Simulated Loss of Offsite Power," Revision 25.

b. Observations and Findings

The inspectors observed the pre-job briefing for the Unit 1 integrated SI test performed near the end of the refueling outage. The briefing was conducted by the shift supervisor and was thorough. Precautions were emphasized and the existing plant status was clearly described. Operators asked pertinent questions and had ample opportunities to have any concerns resolved prior to test performance.

After running the test, the operations department determined that the SI signal was initiated using the wrong manual switch. Per procedure, the SI signal was to be initiated using MSI-1 (CS-46180) at the end of odd fuel cycles, and MSI-2 (CS-46408) at the end of even fuel cycles. This test was performed at the end of fuel cycle 19, so MSI-1 should have been used. During this test, the operators mistakenly determined that this was the end of an even fuel cycle, and used switch MSI-2. The operators also recalled using switch MSI-1 during the previous Unit 1 integrated SI test completed on December 6, 1997. Further review by the licensee determined that switch MSI-1, was also used during the U-1 refueling outage SI test completed on February 22, 1996. Therefore, manual test switch MSI-2 had not been tested for over two fuel cycles.

Technical Specification Table 4.1-1B, "Engineered Safety Feature Actuation System Instrumentation Surveillance Requirements," Item 1.a, required that one SI manual switch shall be tested at each refueling outage on a staggered test basis. On December 6, 1997, the licensee did not stagger the use of the SI initiation manual test switches when SP 1083 was performed. Testing performed at the end of fuel cycles 18 and 19 did meet the staggered test requirements required by TS Table 4.1-1B.

The inspectors determined that the failure to test switch MSI-2 on a staggered test frequency over two fuel cycles was not risk significant because of the redundancy of the manual initiation switches and since the manual SI initiation was not credited in the licensee's probabilistic risk assessment. The licensee placed this issue in their corrective action program (tracking number 19991817) and intended to revise the SP to ensure the SI manual switches were tested on a staggered basis. The licensee also intended to issue LER 1-99-06, "Missed Surveillance Test of Safety Injection Manual Initiation Switch Due to Personnel Error," documenting the failure to perform the surveillance test in accordance with the TS. The LER will be considered open when issued. This Severity Level IV violation is being treated as a Non-Cited Violation consistent with Appendix C of the NRC Enforcement Policy. (NCV 50-282/99004-02(DRP)) This violation is in the licensee's corrective action program under tracking numbers LER 1-99-06 and 19991361.

d. Conclusions

The integrated SI surveillance test, with simulated loss of offsite power, was performed properly except for one discrepancy. The licensee identified that the wrong manual switch was used to initiate SI on May 19, 1999, and previously on December 6, 1997. Although performed out-of-order, the switch testing performed at the completion of the last two outages did meet the TS requirements of staggering the switch testing. However, the test completed in December 1997 did not meet the TS requirement for staggering the switches and was considered an NCV.

**M2 Maintenance and Material Condition of Facilities and Equipment**

M2.1 Safety System Walkdown of Accumulator Injection and RHR Components

a. Inspection Scope (71707)

The inspectors performed a walkdown of accessible SI accumulator and RHR components located in the Unit 1 containment building, focusing on the material condition of components. The inspectors also examined whether system status was consistent with refueling mode operating conditions and whether system design was consistent with the system requirements outlined in USAR.

b. Observations and Findings

The inspectors noted that nine valves had minor packing gland leakage and that two of those valves also had minor body-to-bonnet leakage. The inspector informed the appropriate system engineer of the finding. Overall material condition was considered adequate. All components inspected were clearly labeled and were positioned correctly to support system operation as required for the operating mode.

c. Conclusions

The material condition of the SI accumulator and RHR components in the Unit 1 containment was adequate. No discrepancies were noted in labeling and configuration control of the system components.

**M8 Miscellaneous Maintenance Issues**

M8.1 (Open) LER 50-282/99004; 50-306/99004 (1-99-04): Surveillance Test Procedure Inadequate to Demonstrate Operability of Spent Fuel Pool Special Ventilation System.

a. Inspection Scope (92700)

The inspectors conducted a review of the LER and the associated documents:

- Abnormal Operating Procedure D5.1 AOP 1, "Spent Fuel Pool Area Evacuation - Non-Refueling," Revision 5;
- Abnormal Operating Procedure D5.2 AOP 4, "Spent Fuel Pool Area Evacuation - Refueling," Revision 5;

- Alarm Response Procedure C47022-0109, "Hi Radiation Train A Panel Alarm," Revision 21;

- Alarm Response Procedure C47047 R-25, "Spent Fuel Pool Air Monitor A," Revision 25; and

- USAR Section 14.5.1.3, "FHA in Spent Fuel Pool Area," Revision 14.

b. Observations and Findings

This event, reported on April 2, 1999, involved a licensee-identified discovery that existing surveillance test procedures for testing the spent fuel pool special ventilation system did not adequately verify that the in-service purge system would isolate as required on a high radiation signal. The licensee promptly tested the Unit 1 in-service purge isolation valves and found that they worked properly. The licensee closed the Unit 2 valves until they could be tested. The Unit 2 in-service system was already blanked off, as it normally was during power operation. These actions resolved the immediate safety concerns for the issue.

The inspectors examined the risk significance of this issue if a fuel handling accident had occurred in the spent fuel pool while Unit 2 was shutdown and the in-service purge system was operating. The inspectors assumed that one train of the untested Unit 2 high radiation isolation feature was not operable.

As reported in Section 14.5.1.3 of the USAR, the postulated thyroid dose at the site boundary from a fuel handling accident in the spent fuel pool was very sensitive to the ventilation system being able to rapidly draw a vacuum in the spent fuel pool area. The assumed accident thyroid dose changed from 0.518 Rem to 23.6 Rem if the ventilation system was unable to draw a vacuum for up to one minute. As reported in the LER, failure of the in-service purge system to isolate on a high radiation signal would result in failure of the spent fuel pool special ventilation system to be able to properly draw a vacuum.

The inspectors verified by examination of procedures and a walkthrough with a reactor operator, that the abnormal operating and alarm response procedures for this event would have directed the operator to verify that the automatic actions, including closing of the in-service purge valves, had occurred, and to manually close the valves if they had not closed automatically. The inspectors also verified that indications and controls on the main control board were sufficient for an operator to identify and correct the potential valve problem. The isolation valves were redundant and in series, so two trains of manual isolation capability would have been available. However, based on the walkthrough with the reactor operator, the inspectors estimated that it would take a few minutes to diagnose the problem and manually isolate the in-service purge system. It could also be assumed that the other train of automatic isolation on high radiation would also be available.

At the time of the inspection, neither the inspectors nor the licensee had estimated the initiating event frequency of a spent fuel pool accident. In addition, it was not known whether the Unit 2 in-service purge valves would have actually automatically isolated because they had not been tested. Therefore, this LER will remain open pending a more complete determination of the risk significance of the finding.

The licensee made two corrective action commitments in the LER which the inspectors verified had been entered into the corrective action program. Commitment 19991435 was to review the Generic Letter 96-01 documentation to verify that justifications included in individual packages were appropriate and Commitment 19991436 was to perform the testing on the Unit 2 in-service purge valves.

c. Conclusions

The inspectors developed preliminary information regarding the risk significance of a finding in which the licensee discovered that they had not tested the ability of the containment in-service purge system to automatically isolate on high radiation from a fuel handling accident in the spent fuel pool. The significance determination will be completed when more information becomes available. No conclusions were reached.

## III. Engineering

### E3 Engineering Procedures and Documentation

E3.1 Review of Unit 2 Limited Coverage Third 10-Year Interval Inservice Inspection (ISI) Program Ultrasonic Examinations

a. Inspection Scope (37551)

The inspectors reviewed 22 selected examination records associated with the 1998 Prairie Island Unit 2 refueling outage inservice examinations for the first and second periods of the third 10 year ISI interval. The inspectors selected records for review based on examinations which met the following criteria:

- less than 90% coverage was obtained;
- supplemental examinations were required to increase the coverage due to limitations associated with the examination;
- the examination concerned safety-related components;
- the examination concerned RCS pressure retaining surfaces or components; and
- the examination identified indications or defects.

Documents reviewed as part of this inspection included:

- Prairie Island Nuclear Generating Plant Letter, "Unit 2 Inservice Inspection Summary Report refueling Outage for Cycle No. 19," dated March 30, 1999;
- Prairie Island Nuclear Generating Plant Letter, "Request for Relief No. 8 for the Unit 2 3rd 10-Year Interval Inservice Inspection Program," dated April 1, 1999;
- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1989 Edition (No Addenda), Sections IWB-2500 and IWB 3410;

- Northern States Power Materials and Special Processes Inservice Inspection - Nondestructive Examination Procedure ISI-UT-16, "Ultrasonic Examination of Welds in Austenitic and High Nickel Alloy Materials," Revision 12; and

- Northern States Power Materials and Special Processes Inservice Inspection - Nondestructive Examination (NDE) Procedure ISI-LTS-1,"Limitations to NDE, Revision 1.

b. Observations and Findings

The inspectors reviewed the requirements and guidance found in 10 CFR 50.55a(g) and NRC Information Notice 98-42, "Implementation of 10 CFR Part 50.55a(g) Inservice Inspection Requirements." In those cases where the code required volumetric examination coverage of greater than 90% was not met, the inspectors noted that the licensee correctly documented the examination limitations in accordance with ISI-LTS-1. Code relief was properly requested in accordance with 10 CFR Part 50, Section 50.55a(g)(5)(iii) in a licensee letter dated April 1, 1999. Calibration and examination reports were reviewed by the inspectors and found to contain all the information necessary to understand the equipment, checks, calibrations, scans, and reportable indications associated with the examinations.

For those examinations with recorded indications, the inspectors reviewed the respective flaw location and size calculations to determine if the indications were acceptable in accordance with ASME Section XI Table IWB-3510-1, "Allowable Planar Flaws." The inspectors found that the calculations had been performed correctly and that none of the recorded indications exceeded the code allowable sizes.

Examination Reports 98-0207 (A) and 98-0208(A) documented 45 and 60 degree angle beam inspections of the 22 steam generator tubesheet-to-head weld. The two examination reports documented 48 reportable indications, 31 of which were new indications since the last examination conducted in 1997. The 1997 tubesheet-to-head examinations were performed manually, whereas the 1998 examinations were performed using automated equipment. The inspectors asked the NDE team leader, NDE contractor foreman, and a licensee level II examiner about the characterization of the new flaws. The personnel stated that the flaws were subsurface, original manufacturing, casting flaws and not caused by inservice conditions. The inspectors reviewed NCRs 19982881 and 19990489 and Safety Evaluation Screening 538 which documented a use-as-is disposition of the flaws using fracture mechanics techniques and engineering evaluations. The inspectors found no discrepancies.

The inspectors also reviewed automated ultrasonic number 11 steam generator tubesheet-to-head weld data taken during the Unit 1 refueling outage on April 24, 1999. Examination Reports 99-0352 and 99-0353 documented six reportable indications using a 45 degree angle beam transducer and 11 reportable indications using a 60 degree transducer. The inspectors reviewed the characteristics of the indications with a qualified vendor analyst on a computer analysis station. None of the tubesheet-to-head weld indications exhibited traits of inservice induced flaws. The indications were not inside-diameter connected, tended to be located in the base metal instead of the weld metal, were small in size, and exhibited no tip-diffracted, crack-like signals. Based on these traits, the inspectors agreed with the licencee's assessment of the indications as original manufacturing, non-service induced flaws.

Some minor, editorial discrepancies were noted by the inspectors during the examination record review.

- Procedure ISI-LTS-1, Step 7.1, required that a surface and thickness profile encompassing the required code volume be performed for volumetric examinations. Data concerning the transducer characteristics used in performing the thickness profile were not routinely included in the calibration or examination records. The NDE team leader stated that thickness profile transducer data was only recorded when a thickness measurement was specifically required by code. If the thickness profile was being performed as additional information to be included in angle beam inspections, no thickness profile transducer data was recorded. The incomplete thickness profile documentation made it difficult to determine all of the equipment used to evaluate the soundness of a ISI examined component.

- Procedure ISI-LTS-1, Step 9.4 stated that when limitations to an examination were encountered, a picture of the limitation should be taken and added to the limitation description, preferably in a digital format. For the 22 limited examination records reviewed, no digital photographs of the examination limitations were available. When asked, the NDE team leader stated that digital pictures were not normally taken due to limited availability of digital cameras in the past but that camera availability had recently improved. Although no digital pictures were available, the inspectors noted that drawings and written descriptions attached to the examination records adequately described the scan limitations encountered.

- Five of the twenty-two examination records reviewed did not fully define the transducer scan directions used by the examiners. In reviewing the examination record as a stand-alone document, this made reduced coverage examinations more difficult to understand. The inspectors noted that ISI-UT-16, Figure 3, defined a common reference system used for all scanning directions but that this information had not been explicitly included with five examination records.

- The inspectors noted attention-to-detail errors in three examination reports. In Examination Report 98-0297 the sketch of the limitations encountered for the reducer elbow-to-nozzle configuration included a 3:1 ratio counterbore that was not accurate for the age of piping installed at Prairie Island where a 1:1 ratio counterbore was used. In Examination Report 98-0026, the sketch of the valve-to-elbow configuration did not match the sketch of the limitations encountered for the same examination. In Examination Report 98-0298, the calculations associated with the determination for percent coverage achieved for a 60 degree supplemental had a mathematical error. Supplemental scan 1 actually provided 81.7% coverage instead of the recorded 88.3% coverage. The error, however, did not change the total coverage achieved for the examination (83.8%) since the 45 degree scan 1 direction superceded the coverage obtained with the 60 degree transducer.

c. Conclusions

Limitations associated with 22 examinations of the Unit 2, 3rd 10-year inservice inspection components were adequately documented and ASME Section XI code reliefs appropriately requested. New volumetric indications associated with steam generator tubesheet-to-head and tubesheet-to-shell welds were properly dispositioned as manufacturing, non-service induced flaws. Minor, attention-to-detail errors were noted in the review of ultrasonic scan examination records but they did not affect the overall inspections or conclusions of component operability.

**E8 Miscellaneous Engineering Issues (92700, 92903)**

E8.1 (Closed) LER 50-282/99003; 50-306/99003 (1-99-03): Design Basis Issues Discovered with High-Energy Line Break Analysis Room Over-Pressurization.

This finding was previously discussed in Inspection Report 50-282/99002(DRP); 50-306/99002(DRP), Section E8.3. The issue involved the licensee's discovery, while revising the HELB analysis as part of the USAR review project, that three sets of double airlock doors in the auxiliary building were configured in such a way that they may not have opened to relieve pressure as assumed in the analysis. The consequences of this old design issue could be a harsh environment in an area of the auxiliary building designed for a mild environment, which could affect equipment such as the safety injection and residual heat removal pumps needed to mitigate the accident.

The doors were degraded to the point that an extremely complex analysis would be required to decide if equipment within the area would be to functional following the HELB. This was considered a violation of Appendix B, Criterion III, "Design Control," to 1O CFR Part 50 for failure to establish measures to assure that applicable design basis for structures were correctly translated into design specifications. However, based on implementing the guidance of Section VII.B.3, "Violations Involving Old Design Issues," of the "General Statement of Policy and Procedures for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600, a Notice of Violation is not being issued. (NCV 50-282/99004-03(DRS); 50-306/99004-03(DRS) (EA 99-137)

E8.2 (Closed) Unresolved Item (URI) 50-282/97015-04(DRP); 50-306/97015-04(DRP): Control Room Habitability - Evaluation and Preparedness for Toxic Gas Release.

This issue was previously discussed in Inspection Reports 50-282/97015(DRP); 50-306/97015(DRP), Section E2.2, 50-282/97018(DRP); 50-306/97018(DRP), Section O2.2, and 50-282/97019(DRS); 50-306/97019(DRS), Section O8.1.

This item involved several inspector concerns regarding the fact that some potentially toxic chemicals stored onsite had never been evaluated for their effect on control room habitability and that control room operators' ability to respond to a habitability problem may not have been adequate for a variety of reasons, such as lack of training, lack of sufficient numbers of self contained breathing units, and lack of corrective lenses that were compatible with breathing units. Many of the issues were previously resolved as discussed in the inspection reports listed above.

On February 24, 1999, the licensee's Operating Committee reviewed and concurred with Safety Evaluation 50-520, "Evaluation of Control Room Habitability During a

Postulated On-Site Hazardous Chemical Release," Revision 0. That study documented an evaluation of the effects of certain chemicals, such as carbon dioxide and propane, that were not included in the original toxic gas analysis completed in earlier studies. The conclusion in the safety evaluation was that none of the chemicals would have a significant adverse effect on control room habitability. The inspectors had no concerns with the evaluation.

E8.3 (Closed) LER 50-282/99002(DRP); 50-306/99002(DRP) (2-99-02), Supplement 2: Defect in Primary System Pressure Boundary Observed on the Motor Tube Base of Part Length CRDM [Control Rod Drive Mechanism] Housing.

This supplement documented the completion of the replacement of the four Unit 1 part length CRDMs with head adapter plugs. The licensee concluded that the defect in Unit 2 part length CRDM G9 which precipitated the replacement, was an isolated event most likely was caused by the introduction of contaminants during the original weld fabrication process. The inspectors had no further concerns with this issue.

E8.4 Review of Year 2000 (Y2K) Readiness

(Closed) TI 2515/141: Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants.

The inspectors conducted an abbreviated review of Y2K activities and documentation using TI 2515/141. The review addressed aspects of Y2K management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The inspectors used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review. The results of this review will be combined with the results of other reviews in a summary report to be issued by July 31, 1999.

## IV. Plant Support

### R1 Radiological Protection and Chemistry Controls (71750, 92904)

R1.1 Unit 1 Hot Spots in Reactor Cavity Transfer Canal Sump

a. Inspection Scope (71750)

During Unit 1 reactor cavity draining on May 8-9, 1999, the licensee discovered at least three hot spots in the reactor cavity sump in the vicinity of the fuel transfer equipment. The hot spots measured approximately 600 R/hr, 200/R/hr, and 50 R/hr. The inspectors attended pre-job briefings and observed the removal of some of the hot spots from the reactor cavity sump.

b. Observations and Findings

After identifying the hot particles on May 9, 1999, the licensee partially filled the reactor cavity sump with water to provide shielding while hot spot removal plans were developed. Planning meetings were held on May 10, and the licensee decided to use a remotely operated pneumatic tool at the end of a 12-foot pole to retrieve and place the hot particles in a specially fabricated lead cask.

The inspectors attended the pre-job briefing and observed portions of the first retrieval attempt process on May 12, 1999. The pre-job briefing was complete and included personnel responsibilities, expected dose rates, contingency actions, and communications. One construction laborer and two health physics technicians attempted to retrieve the hot particles. The construction laborer and health physics technicians in the vicinity of the reactor cavity sump wore remote dosimetry which was continuously monitored by a radiation protection supervisor. The three personnel spent approximately 1.5 hours attempting to retrieve the hot particles and received a cumulative dose of 20 mrem.

Four radiation detection instruments were used during the retrieval process, including an RO-7 probe capable of taking radiation readings while submerged, two teletector probes, and a AM-2 general area radiation monitor above the water surface. The two health physic technicians consistently monitored radiation levels on the surface of the water in the reactor cavity sump and made good use of the underwater RO-7 probe to monitor hot spot movement underwater. Using similar methods, the licensee made a second attempt to retrieve the hot particles on the evening of May 12.

On May 14, 1999, a lead cask containing some of the hot particles was transported from the reactor cavity sump to the spent fuel pool. The inspectors attended the pre-job briefing and noted that all personnel involved in the transport were present including maintenance riggers, construction laborers, health physics technicians, a nuclear engineer, the duty shift manager, an operator, and the superintendent of radiation protection. The pre-job brief was thorough and discussed the sequence of events, personnel responsibilities, expected dose rates, contingency actions, rigging, and past incidents. The transport of the hot particles to the spent fuel pool occurred without problems. Remaining activity in the reactor cavity sump was drained to the Unit 1 containment sump A and the cavity subsequently decontaminated. The overall dose associated with all work involving the hot particles was 182 mrem. Considering the high activity of the particles and the amount of time needed to remove them, the relatively low dose received during the work indicated that planning, control, and execution of the work was good.

c. <u>Conclusions</u>

Following refueling activities, the licensee identified hot particles in the Unit 1 reactor cavity sump, the highest of which read 600 R/hr on contact. Radiation protection personnel responded appropriately and took sufficient time to consider all options for removing the hot particles from the reactor cavity sump. The hot particles were removed in a controlled and deliberate manner with a remotely operated tool and close health physics supervision. Total dose for removing the hot particles from the cavity sump was 182 mrem which reflected a plan that was devised and executed well.

**S1 Conduct of Security and Safeguards Activities (71750, 92904)**

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were consistent with the approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors also verified that checked vital areas were locked and alarmed. Additionally, the inspectors also verified that observed personnel and packages entering the protected area were searched by appropriate equipment or by hand.

## V. Management Meetings

### X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management on May 28, 1999. Additional information on the Y2K readiness inspection was discussed on May 7, 1999. 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

T. Amundson, General Superintendent Engineering
J. Goldsmith, General Superintendent Engineering, Nuclear Generation Services
J. Hill, Nuclear Performance Assessment Manager
A. Johnson, General Superintendent Radiation Protection and Chemistry
G. Lenertz, General Superintendent Plant Maintenance
J. Maki, Outage Manager
D. Schuelke, Plant Manager
T. Silverberg, General Superintendent Plant Operations
M. Sleigh, Superintendent Security
J. Sorensen, Site General Manager

## INSPECTION PROCEDURES USED

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

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-282/99004;<br>50/306/99004 (1-99-04) | LER | surveillance procedure inadequate to demonstrate operability of spent fuel pool special ventilation system |
| 50-282/99004-01(DRP) | NCV | failure to properly control component with attached safeguards hold tag |
| 50-282/99004-02(DRP) | NCV | failure to test manual SI actuation switches on a staggered test basis |
| 50-282/99004-03(DRS);<br>50-306/99004-03(DRS)<br>EA 99-137 | NCV | failure to control the design basis of airlock doors in the auxiliary building |

Closed

| | | |
|---|---|---|
| 50-282/97015-04;<br>50-306/97015-04 | URI | control room habitability - evaluation and preparedness for toxic gas release |
| 50-282/98002;<br>50-306/98002 (2-98-02);<br>Supplement 2 | LER | defect in primary system pressure boundary observed on the motor tube base of part length CRDM housing |
| 50-282/99003;<br>50-306/99003 (1-99-04) | LER | design basis issues discovered with high energy line break analysis room over-pressurization |
| 50-282/99004-01(DRP) | NCV | failure to properly control component with attached safeguards hold tag |
| 50-282/99004-02(DRP) | NCV | failure to test manual SI actuation switches on a staggered test basis |
| 50-282/99004-03(DRS);<br>50-306/99004-03(DRS)<br>EA 99-137 | NCV | failure to control the design basis of airlock doors in the auxiliary building |

Discussed

None

## LIST OF ACRONYMS USED

| | |
|---|---|
| AB | Abnormal Procedure |
| AFW | Auxiliary Feedwater |
| ASME | American Society of Mechanical Engineers |
| AWI | Administrative Work Instruction |
| CFR | Code of Federal Regulations |
| CRDM | Control Rod Drive Mechanism |
| DC | Direct Current |
| DRP | Division of Reactor Projects |
| DRS | Division of Reactor Safety |
| EA | Enforcement Action |
| ERTF | Error Reduction Task Force |
| FHA | Fuel Handling Accident |
| HELB | High Energy Line Break |
| ISI | Inservice Inspection |
| LER | Licensee Event Report |
| NCR | Nonconformance Report |
| NCV | Non-Cited Violation |
| NDE | Nondestructive Examination |
| NRC | Nuclear Regulatory Commission |
| PCR | Procedure Change Request |
| RCP | Reactor Coolant Pump |
| RCS | Reactor Coolant System |
| RHR | Residual Heat Removal |
| SAC | Safety Audit Committee |
| SI | Safety Injection |
| SP | Surveillance Procedure |
| SWI | Section Work Instruction |
| TCN | Temporary Change Notice |
| TS | Technical Specification |
| URI | Unresolved Item |
| USAR | Updated Safety Analysis Report |
| WO | Work Order |
| Y2K | Year 2000 |