November 8, 1999

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

SUBJECT: PRAIRIE ISLAND INSPECTION REPORT 50-282/99013(DRP); 50-306/99013(DRP)

Dear Mr. Wadley:

On October 13, 1999, the NRC completed a baseline inspection at your Prairie Island Nuclear Generating Plant. The results of this inspection were discussed on October 13, 1999, with Mr. J. Sorensen and other members of your staff. The enclosed report presents the results of that inspection.

The inspection was an examination by the resident inspectors and senior reactor analysts of activities conducted under your license as they relate to reactor safety, identification and resolution of problems, verification of performance indicators, event followup, and compliance with the Commission=s rules and regulations and with the conditions of your license. Within these areas the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC identified three issues of very low safety significance that have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached report. One of these issues was determined to involve a violation of NRC requirements. Because of its very low safety significance, the violation was not cited. If you contest this noncited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector the Prairie Island facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

/s/ R. Lanksbury

Roger Lanksbury, Chief
Reactor Projects Branch 5

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

Enclosure: Inspection Report 50-282/99013(DRP);
50-306/90013(DRP)

cc w/encl: Site General Manager, Prairie Island
Plant Manager, Prairie Island
S. Minn, Commissioner, Minnesota
Department of Public Service
State Liaison Officer, State of Wisconsin
Tribal Council, Prairie Island Dakota Community

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REGION III

Docket Nos:	50-282, 50-306
License Nos:	DPR-42, DPR-60
Report No:	50-282/99013(DRP); 50-306/99013(DRP)
Licensee:	Northern States Power Company
Facility:	Prairie Island Nuclear Generating Plant
Location:	1717 Wakonade Drive East Welch, MN 55089
Dates:	September 1 through October 13, 1999
Inspectors:	S. Ray, Senior Resident Inspector S. Thomas, Resident Inspector S. Burgess, Senior Reactor Analyst
Approved by:	Roger Lanksbury, Chief Reactor Projects Branch 5 Division of Reactor Projects

SUMMARY OF FINDINGS

Prairie Island Nuclear Generating Plant, Units 1 & 2
NRC Inspection Report 50-282/99013(DRP); 50-306/99013(DRP)

The report covers a 6-week period of resident inspection.

Inspection findings were evaluated according to their potential significance for safety, using the NRC=s Significance Determination Process, and assigning colors of GREEN, WHITE, YELLOW, or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent little effect on safety. WHITE findings indicate issues with some increased importance to safety which may require additional NRC inspections. YELLOW findings are more serious issues with an even higher potential to affect safe performance and would require the NRC to take additional actions. RED findings represent an unacceptable loss of margin to safety and would result in the NRC taking significant actions that could include ordering the plant shut down. Those findings that cannot be evaluated for a direct effect on safety with the Significance Determination Process, such as those findings that affect the NRC=s ability to oversee licensees, are not assigned a color.

Cornerstone: Mitigating Systems

! GREEN. On June 25, 1999, the licensee discovered that the door into the 122 control room chiller room was inoperable as a high-energy line break barrier because of broken latch pins. The pins were repaired within 1 hour of the discovery. On July 27, 1999, the licensee again discovered the same condition and repaired the latch pins within 1 hour. On August 12, 1999, the licensee determined that the latch pins on both the 121 and 122 control room chiller room doors, even when intact, may never have been able to perform their safety function because of inadequate material strength. As discussed in previous inspection reports, the NRC considered the issues to be potentially risk significant because of the possibility of a main steamline break introducing a steam environment into the control room and affecting multiple mitigation systems on both units simultaneously.

  Using Phase 3 of the Significance Determination Process, the NRC reviewed licensee-supplied calculations and determined that the issues were of very low risk significance because of a low initiating event frequency and a high-energy line break re-analysis that showed that compartment pressures would be lower than originally assumed. Therefore, the issues were determined to be within the licensee response band. (Section 4OA3.1)

! GREEN. On September 30, 1999, during post-maintenance testing activities on the Unit 1, D2 emergency diesel generator, an operator cross-connected the D1 and D2 starting air receivers. The inspectors identified that the operator failed to correctly follow the applicable operating procedure and allowed the D1 air receiver pressure to fall to about 185 pounds per square inch gauge (psig). This was below the minimum specified value of 200 psig specified in the procedure. Had initial pressures in either of the air receivers been lower, the final pressure for D1 might have fallen below the operability limit of 175 psig, resulting in both Unit 1 diesel generators being simultaneously inoperable. This finding was entered into the licensee=s corrective action process after the inspectors notified licensee management that it originally had not been entered.

Using the Significance Determination Process, the NRC determined that the issue was of very low risk significance since the operator error did not result in the D1 emergency diesel generator actually becoming inoperable. Therefore, this issue was determined to be within the licensee response band. This issue was determined to be a Non-Cited Violation (NCV) for improper procedure implementation. The tracking number for this NCV is 50-282/99013-01(DRP). (Section 1R03)

! GREEN. During the performance of a Unit 1 reactor coolant system draining evolution, which was intended to drain the reactor coolant system from 1 foot below the reactor flange to the top of the hot legs, approximately 1500 additional gallons were unintentionally drained. The report of the licensee=s investigation reported that, on four separate occasions, the operating crew deviated from the applicable special operating procedure which provided instructions for the draining evolution. The inspectors concluded that the procedure deviations significantly contributed to the unintentional overdraining.

Using the Significance Determination Process, the NRC determined that the finding was of very low risk significance because, although the loss of additional reactor coolant system inventory slightly impacted the time to boiling in the core should residual heat removal capability have been lost, the total amount of water that could be drained was limited by a self-limiting system configuration. Because of the drain piping design, the loss of inventory could not have resulted in a loss of residual heat removal capabilities. Therefore, this issue was determined to be within the licensee response band. The inspectors identified a potential violation regarding improper procedure implementation. Pending final evaluation of the procedural noncompliances and a characterization of those noncompliances in the licensee=s formal root cause evaluation, this potential violation was being treated as an Unresolved Item. (Section 4OA3.2)

Performance Indicator Verification
Cornerstone: Initiating Events

! Unplanned Power Changes per 7000 Critical Hours. The inspectors evaluated the performance indicator data submitted for Unit 1 and Unit 2 covering the time period from the third quarter of 1998 through August 31, 1999. The inspectors identified one error in the second quarter of 1999 data for Unit 1. The reported critical hours for the second quarter showed 1 extra hour (1268 vs 1267) of critical operation. The error was in the conservative direction and attributed to incorrectly incorporating the loss of an hour due to the daylight savings time change. The licensee informed the inspectors that the error will be corrected in their next performance indicator data submittal. The calculation of the performance indicator using the correct number of critical hours did not result in the crossing of a response threshold and the performance indicator remained in the GREEN licensee response band. (Section 4OA2)

Report Details

During this inspection period both units operated at or near full power with the exception of Unit 2 which was briefly brought to about 50 percent power on September 26, 1999, for quarterly turbine valve testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R03 Emergent Work

a. Inspection Scope

The inspectors observed the following emergent work activities and reviewed the Work Orders (WOs):

! WO 9911073, ARepair D2 Station Air Compressor@;

! Operating Procedure C31, AFire Protection and Detection Systems,@ Revision 25, for recovery from an inadvertent deluge valve activation for the fire protection header that supplied water to the D5 emergency diesel generator (EDG) room;

! WO 9803805, ASupport of New Breaker Installation in Cubicle 12-6,@ for correction of a misalignment between the breaker and support frame; and

! WO 9911035, AFlush 2VC-14-1 and 2VC-14-2, Reactor Coolant Pump Seal Injection Needle Valves,@ for correction of a low seal injection flow problem for the 21 and 22 reactor coolant pumps.

b. Observations and Findings

For the emergent work on the D2 EDG starting air compressor, the inspectors identified that an operator failed to properly follow a procedure, creating the possibility of making the D1 EDG inoperable while the D2 EDG was already inoperable. This issue was determined to be a Non-Cited Violation for failure to follow an approved procedure.

On September 30, 1999, the licensee elected to continue with ongoing D2 post-maintenance testing activities while the air compressor was out-of-service. This required that the D1 and D2 starting air receivers be cross-connected whenever the D2 receiver pressure became too low to support engine starting. The operators used Temporary Change Notice (TCN) 1999-0936 to Operating Procedure 1C20.7, AD1/D2 Diesel Generators,@ Revision 10, to perform that task. Step 5.4.10.6 of the TCN stated, AThrottle OPEN SA-26-1, D1/D2 STARTING AIR X-CONN AND MAINTAIN greater than 200 psig [pounds per square inch gauge] in D1 starting air receiver while pressurizing D2 starting air receiver.@ The inspectors observed operators cross-connect the air receivers using the procedure TCN. The D1 air receiver was initially at about 230 psig and the D2 air receiver was at about 140 psig. The inspectors identified that the operator opened valve SA-26-1 far enough that pressure rapidly equalized between the two air receivers. Pressure equalized at about 185 psig, below the specified 200 psig, and then slowly increased as the D1 air compressor recharged the receivers.

Although not described in Technical Specifications or the Updated Safety Analysis Report, the licensee would consider the diesel generator inoperable if starting air receiver pressure was below the low pressure alarm setpoint of 175 psig (see Section 1R15 of this report). Had the initial pressures of either the D1 or D2 receivers been lower before being cross-connected, the evolution could have resulted in the operable D1 diesel generator becoming inoperable at the same time that the D2 diesel generator was undergoing maintenance. Thus, failure of the operator to properly follow TCN 1999-0936 created a potential increase in risk. Contributing factors to the failure to meet the requirements of the procedure were that the valve being operated was not designed as a throttle valve and that the air receiver pressure gauges were not readily visible from the valve location.

The inspectors performed a risk significance screening in accordance with NRC Inspection Manual Chapter 06XX, ASignificance Determination Process [SDP].@ Since the operator error did not result in the D1 diesel generator actually becoming inoperable, the issue was of very low risk significance and was screened out from further review. The finding was considered to be within the licensee response band (GREEN) and was assigned to the Mitigating Systems cornerstone for Unit 1. See Section 4OA1.b for corrective actions.

Technical Specification 6.4.A required that applicable procedures recommended in Regulatory Guide 1.33, AQuality Assurance Program Requirements (Operations),@ Revision 2, Appendix A, February 1978, be established, implemented, and maintained. Contrary to this, on September 30, 1999, TCN 1999-0936 to Operating Procedure 1C20.7, AD1/D2 Diesel Generators,@ Revision 10, a system operating procedure recommended in Regulatory Guide 1.33, was not implemented properly in that starting air receiver pressure on the D1 diesel generator was allowed to go below the limit specified in the procedure. This violation is being treated as a Non-Cited Violation (NCV) consistent with the Interim Enforcement Policy for pilot plants, Appendix F of the NRC Enforcement Policy (50-282/99013-01(DRP)). This violation is in the licensee=s corrective action program as issue 19992927.

There were no findings identified and documented for the other three emergent work activities inspected.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors performed equipment alignment walkdowns of the following systems or trains:

! Residual heat removal Train 22 while the 21 residual heat removal train was inoperable for preventive maintenance; and

- ! D1 emergency diesel generator and support equipment while the D2 EDG was out-of-service for its once-per-18-month planned maintenance period. Also included was a check of the availability of Unit 1, Train A, safeguards equipment. This walkdown met the requirements for the semiannual equipment walkdown.

b. Observations and Findings

The were no findings identified and documented during these inspections.

1R05 Fire Protection

a. Inspection Scope

The inspectors preformed fire protection walkdowns of the following areas:

- ! fire zone 1 (11 and 12 station battery rooms) and
- ! fire zone 35 (21 and 22 station battery rooms). .

In addition, the inspectors completed an observation of the licensee=s annual fire brigade drill. The drill was for a simulated fire in the D5 emergency diesel generator room. The inspectors also attended the licensee critique following the drill.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the associated procedure and observed the licensee=s inspections of the following raw water heat exchangers during the conduct of preventive maintenance (PM) being performed in accordance with PM 3002-2-22, A22 Diesel Cooling Water Pump Annual Inspection,@ Revision 18:

- ! angle gear driver oil cooler on the 22 diesel-driven cooling water pump and
- ! jacket water heat exchanger on the 22 diesel-driven cooling water pump.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R09 Inservice Testing

a. Inspection Scope

The inspectors observed the following inservice testing activities and reviewed the associated surveillance test procedures (SPs):

! SP 2089, AResidual Heat Removal Pumps and Suction Valves from the Refueling Water Storage Tank,@ Revision 53;

! SP 1130, AContainment Vacuum Breakers Quarterly Tests,@ Revision 31; and

! SP 1356, AThermal Barrier Check Valve Test,@ Revision 3.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R10 Large Containment Valves

a. Inspection Scope

The inspectors observed testing of the Unit 2, Train A, containment vacuum breakers in accordance with SP 2130, AContainment Vacuum Breakers Quarterly Test,@ Revision 35, and reviewed the procedure.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed the performance of an operating crew during a simulator exercise on September 29, 1999. The inspectors also reviewed the associated training evaluation and critique. The simulator scenario included a loss-of-coolant accident outside of containment and a failure of the safety injection system to automatically actuate.

b. Observations and Findings

There were no findings identified and documented during this inspection. One minor observation was identified. During the scenario, operators started the safety injection pumps but failed to initially open the pump suction valves (the valves were closed as part of the senerio). The inspectors observed that the success criteria in the simulator evaluation for the critical task of operators recognizing and correcting that problem was based on completing the task before exiting the applicable emergency operating procedure rather than on a reasonable time which would ensure that the pumps would not be damaged. Thus, crew performance could be judged as successful on the simulator even when the pumps might have been damaged in an actual event. This issue was identified at the end of the inspection period and the licensee was reviewing it for corrective actions.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the implementation of the maintenance rule requirements for the following issues:

! a failure of 1M transformer;

! vibration from 21 containment spray pump;

! the 122 control room chiller room locking mechanism failure; and

! discharge valve found closed on 2R11/12 air monitor.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R13 Maintenance Work Prioritization

a. Inspection Scope

The inspectors reviewed and observed the licensee=s evaluation of plant risk and configuration control associated with the repair of erosion damage to the cooling water intake bay canal bank under WO 9908277, AAdd Rock to Banks of Intake Canal in Security Zones 8 and 9.@

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following operability evaluations:

! Automated Engineering Services Corporation Calculation PI-S-034, AStructural Evaluation of Door 182 with Bottom Latch Rod Inadvertently Lodged in the Door Threshold and Hole in Concrete Floor,@ Revision 0. The evaluation established that the door would have opened as required under high-energy line break conditions.

! Design Basis Document SYS-38A, AEmergency Diesel Generator System,@ Revision 2 and Work Request S2437-D2-0, AOperationally Test the Ability of One Diesel Generator Air Start Receiver to Crank the Engine for 20 Seconds,@ dated April 2, 1992. These documents established that the D1 and D2 EDG air start systems could meet their design basis with receiver pressure initially at the low pressure alarm setpoint of 175 psig.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed Operator Workaround 19992576, AUnit 1 and Unit 2 Moisture Separator Reheater Steam Supply Control Valves Leak By, Emergency Operating Procedures Require Manual Operator Action To Isolate Steam Supplies.@

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors observed the following post-maintenance testing activities and reviewed the associated procedures:

! WO 9803805, ASupport of New Breaker Installation In Cubicle 12-6,@ following breaker installation;

! SP 1307, AD2 Diesel Generator Fast Start Test,@ Revision 16, following the generator and engine=s 18-month PM; and

! SP 1106B, A22 Diesel Cooling Water Pump Test,@ Revision 53, following the pump and engine=s annual PM.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed the following surveillance testing activities and reviewed the associated procedures:

! SP 1032C, ASafeguards Boric Acid Logic Test,@ Revision 6;

! SP 1544, AU1 Containment At Power Inspection,@ Revision 30; and

! SP 2091, AMonthly Containment Fan Coil Units Surveillance Test,@ Revision 22.

b. Observations and Findings

There were no findings identified and documented during these inspections.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors inspected the following temporary modifications and reviewed the associated documentation:

! Temporary Modification 98T057, AAuxiliary Building Normal Ventilation Suction From the Waste Gas Compressor Room; and

! Mechanical Bypass Work Order 9904653, ABall Valve at 121 Fire Protection Jockey Pump Discharge Tubing.@

b. Observations and Findings

There were no findings identified and documented during these inspections.

4. OTHER ACTIVITIES

4OA1 Identification and Resolution of Problems
Crosscutting Issues

a. Inspection Scope

Throughout the inspection activities discussed in this report, the inspectors verified that problems identified by either licensee personnel or the inspectors were promptly entered into the licensee=s corrective action system.

b. Observations and Findings

There were no findings identified and documented during this inspection. Two minor observations were identified where licensee personnel failed to promptly enter identified problems into the corrective action system.

- As discussed in Section 1R03 of this report, on September 30, 1999, the inspectors identified that an operator had allowed the D1 diesel generator air receiver pressure to drop below the specified value in the procedure while cross-connecting the receiver to the D2 diesel generator. The inspectors immediately discussed the observation with the shift supervisor. Subsequently, the shift manager counseled the operator.

  On October 5, 1999, the inspectors noted that the event had not been documented in the licensee's corrective action system. The inspectors discussed that observation with the general superintendent of plant operations. The general superintendent then entered the event into the corrective action system as Issue 19992927.

- As listed in Section 1R09 of this report, on September 1, 1999, the inspectors observed inservice testing on one of the residual heat removal pumps. One step in the procedure was to verify that the unit cooler fans were running after the residual heat removal pump was started. The purpose of the step was to verify that the automatic start feature of the unit cooler fans was operable. However, the inspectors noted that the fans were already running in manual before the start of the test. The inspectors discussed the issue with the operating crew in the pre-job briefing and the shift supervisor directed the operators to secure the fans and place them in automatic before the start of the pump. The system engineer remarked that other operators had noted the same problem with the other three residual heat removal pumps tested earlier in the week and that the operators had taken the same compensatory action to ensure that the test verified that the fans automatically started. The operators and engineer agreed that SP 1089 and SP 2089 should be changed to include a prerequisite step to place or verify the unit cooler fans in automatic before the start of the test.

  Approximately 3 weeks later the inspectors observed that no procedure change requests or other corrective action documents had been initiated to resolve the problem. The observation was discussed with members of the plant management staff and Nonconformance Report 19992817 was then issued by an engineering superintendent.

4OA2 Performance Indicator Verification
Cornerstone: Initiating Events

a. Inspection Scope

The inspectors verified the performance indicator data reported by the licensee for unplanned power changes per 7000 critical hours for both Unit 1 and Unit 2 for the time period covering the third quarter of 1998 through August 31, 1999.

b. Observations and Findings

The inspectors identified one error in the data for the second quarter of 1999 for Unit 1. The reported critical hours for the quarter showed 1 extra hour (1268 vs 1267) of critical operation. This was attributed to incorrectly incorporating the loss of an hour because of the daylight savings time change. The licensee informed the inspectors that the error would be corrected in the next performance indicator data submittal. Recalculation of the performance indicator using the correct number of critical hours did not result in the crossing of a response threshold and the performance indicator remained in the GREEN licensee response band.

4OA3 Event Follow-up
Cornerstone: Mitigating Systems

.1 (Closed) Apparent Violation (AV) 50-282/99007-03(DRP); 50-306/99007-03(DRP): Control Room Special Ventilation System Inoperable Longer than Allowed by Technical Specification 3.13.A.1 due to Problem with Chiller Room Door Latches.

a. Inspection Scope

The NRC completed a review of potentially risk-significant issues previously discussed in Inspection Reports 50-282/99006(DRP); 50-306/99006(DRP), Section 4OA3, and 50-292/99007(DRP); 50-306/99007(DRP), Section 4OA3. The issues involved the licensee=s discovery, on two occasions, that the latch pins were broken on the door to the 121 control room chiller room, and the later discovery that the pins, even when intact, may never have been strong enough to withstand a high-energy line break (HELB). This review was conducted in accordance with Phase 3 of the SDP in NRC Inspection Manual Chapter 06XX, ASignificance Determination Process.@

b. Observations and Findings

Based on a review of licensee-supplied calculations for the initiating event frequency and consequences of a main steamline break (MSLB) in the auxiliary building, the NRC determined that the issue of the degraded or broken door latch pins on the control room ventilation system chiller room doors was of very low risk significance.

Degraded or broken door latch pins were hypothesized to have potentially allowed the doors to swing open into the chiller room with a small differential pressure on the outside such as would be expected after a HELB in the auxiliary building. The wall between the 122 and 121 chiller rooms and the control room ducting in the chiller rooms were not qualified for harsh environment of a HELB; therefore, this may have represented a loss of the steam exclusion boundary between the auxiliary building and the chiller room/control room ventilation envelope. This condition may have existed since plant construction.

The NRC performed a Phase 3 SDP evaluation using the licensee=s plant-specific, probabilistic risk assessment (PRA) information. Specifically, the Senior Reactor Analysts reviewed the licensee=s results from a HELB re-analysis (Calculation PI-S-037), calculations supporting plant-specific, main steamline break (MSLB) initiating event frequencies (Calculation V.SMD.95.008), an original latch pin strength calculation (Calculation PI-S-037), and a requantification of a MSLB event tree from Prairie Island=s PRA computer model.

The licensee=s HELB re-analysis concluded that the original latch pins securing the double doors were capable of withstanding the HELB compartment pressure and would have prevented the potential steam environment from entering into the safeguards chiller rooms and the control room. Therefore, additional mitigating equipment that was assumed to be unavailable in the initial SDP, because of the steam environment in the control room, would have been available to mitigate the postulated accident conditions. In addition, the plant-specific, initiating event frequency for a MSLB, as documented in Licensee Event Report (LER) 1-99-007, was two orders in magnitude lower than that used by the NRC in the initial SDP evaluation.

Using a plant-specific PRA model, the licensee requantified the MSLB event tree with the 122 control room chiller unavailable (due to the broken latch pin) and determined that there was no increase in the core damage probability. Based on the analyses provided, the Senior Reactor Analysts agreed with the licensee=s evaluation and concluded that this finding was within the licensee response band (GREEN) because of adequate mitigation capability and very low risk significance. The finding was assigned to the Mitigating Systems cornerstone for both units.

The licensee=s analysis demonstrated that the latch pins would have performed their safety function while they were intact. As discussed in the previously mentioned inspection reports, on the two occasions where the latch pins were found to be broken, they were repaired within the allowed outage time of Technical Specifications. Thus, the finding was not considered to be a violation of NRC requirements.

.2 Unit 1 Reactor Coolant System (RCS) Overdraining Event

a. Inspection Scope

The inspectors reviewed the root cause analysis, as documented in the Error Reduction Task Force (ERTF) Report 99-07, AOverdrain of Unit 1 RCS While Draining to the Top of the Hot Legs,@ of an event which occurred on April 20, 1999. This event was initially documented in Inspection Report 50-282/99004(DRP); 50-306/99004(DRP), Section O1.2.

b. Observations and Findings

The licensee=s report identified four instances in which the procedure was not followed during draining of the RCS. However, the self-limiting design of the drain path would have prevented a loss of residual heat removal do to low pump suction head pressure.

The licensee conducted a thorough and comprehensive root-cause investigation. The root-cause analysis, as documented in the ERTF Report 99-07, identified several inappropriate operator actions and proposed eleven corrective actions.

The inspectors evaluated the ERTF report and determined that the most significant deficiencies which contributed to the overdrain of the RCS were related to improper procedure usage. Special Operating Procedure 1D2, ARCS Reduced Inventory Operation,@ Revision 8, provided instructions for draining the RCS from 1 foot below the reactor vessel flange to below the top of the RCS hot leg to facilitate steam generator nozzle dam installation. On four separate occasions the operating crew deviated from the instructions provided by Procedure 1D2. The four deviations were:

! the operator assigned to monitor the plastic tube RCS level indicator inside containment did not attend the evolution pre-job briefing as required by Step 5.1.13 of 1D2;

! the operating crew did not verify that RCS level had stopped decreasing, as required by Step 5.2.13.F of 1D2, after the water from the 12 steam generator tubes was drained.

! while aligning equipment to drain the tubes for the 11 steam generator, the operating crew performed Steps 5.2.18 through 5.2.21 out of sequence in order to restore the plastic tube RCS level indication introducing to an accurate reading by purging the 11 steam generator with nitrogen; and

! the operating crew did not verify that RCS level had stopped decreasing, as required by Step 5.2.24.F, after the water from the 11 steam generator tubes was drained.

The inspectors concluded that, even though the additional water drained from the RCS had some impact on core boiling time, because of the physical location where the drain line penetrated the RCS cold leg piping and where the pressurizer surge line penetrated the RCS hot leg piping, the RCS level decrease was self-limiting and the RCS level could not have decreased to a point that would have impacted residual heat removal pump operability. The inspectors performed a risk-significance screening in accordance with NRC Inspection Manual Chapter 06XX, ASignificance Determination Process.@ Since residual heat removal was not impacted and the amount of water that could be drained from the RCS was limited by system configuration and alignment, the issue was considered to be of very low safety significance, was screened out from further review, and was considered to be within the licensee response band (GREEN). The finding was assigned to the Mitigating Systems cornerstone for Unit 1.

The ERTF report also identified other factors which contributed to the RCS overdrain event. These factors included: operators not taking full advantage of all level indications available; unclear procedural guidance; operators not fully understanding the impact on system parameters of nitrogen pressure on the reactor vessel; and lack of a questioning attitude by the operators when they encountered unexpected responses during the draining evolution. The draining procedures for both units had been quarantined pending review and revision. The proposed corrective actions associated with this event had been entered in the licensee corrective action program and were being tracked as Issue 19991384.

Pending final evaluation of the procedural noncompliances and a characterization of those noncompliances in the licensee's formal root cause evaluation, this potential violation is being treated as an Unresolved Item (URI), (50-282/99013-02(DRP)).

4OA4 Other

Cornerstone: Mitigation Systems

(Closed) LER 50-282/99007; 50-306/99007 (1-99-007), Original and Revision 1: Loss of Control Room Special Ventilation Function Due to Broken/Inadequate Door Latch Pins on Control Room Chiller Doors. These reports dealt with the issues discussed in Section 4OA3.1 of this report. The NRC determined that the issues were of very low risk significance. Remaining corrective actions were in the licensee's corrective action program.

4OA5 Meetings, including Exit

Exit Meeting Summary

The inspectors presented the inspection results to Mr. J. Sorensen and other members of licensee management at the conclusion of the inspection on October 13, 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
R. Hansen, Probabilistic Risk Assessment Engineer
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

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-282/99013-02(DRP)	URI	Failure to follow procedure on four occasions when draining the reactor coolant system

Opened and Closed

50-282/99013-01(DRP)	NCV	Failure to follow procedure for cross-connecting the D1 and D2 diesel generator starting air receivers

Closed

50-282/99007-03(DRP); 50-306/99007-03(DRP)	AV	Control room special ventilation system inoperable longer than allowed by Technical Specification 3.13.A.1 due to problem with chiller room door latches
50-282/99007-00; 50-306/99007-00 (1-99-007 Revision 0)	LER	Loss of control room special ventilation function due to broken/inadequate door latch pins on control room chiller doors
50-282/99007-01; 50-306/99007-01 (1-99-007 Revision 1)	LER	Loss of control room special ventilation function due to broken/inadequate door latch pins on control room chiller doors

LIST OF ACRONYMS USED

AV	Apparent Violation
DRP	Division of Reactor Projects
EDG	Energy Diesel Generator
ERTF	Error Reduction Task Force
HELB	High-Energy Line Break
LER	Licensee Event Report
MSLB	Main Steamline Break
NCV	Noncited Violation
NRC	Nuclear Regulatory Commission
PM	Preventive Maintenance
PRA	Probabilistic Risk Assessment
psig	Pounds per Square Inch Gauge
RCS	Reactor Coolant System
SDP	Significance Determination Process
SP	Surveillance Procedure
TCN	Temporary Change Notice
URI	Unresolved Item
WO	Work Order