U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-263/91022(DRP)

Docket No. 50-263 License No. DPR-22

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

Facility Name: Monticello Nuclear Generating Station

Inspection At: Monticello Site, Monticello, MN

Inspection Conducted: December 1, 1991, through January 21, 1992

Inspectors: S. Ray

W. Stearns

Approved By: R W DeFayette
R. W. DeFayette, Chief
Reactor Projects Section 2B

FEB 06 1992
Date

Inspection Summary

Inspection on December 1, 1991, through January 21, 1992 (Report No. 50-263/91022(DRP))

Areas Inspected: A routine, unannounced inspection by the resident inspectors of operational safety verification; onsite followup of events; cold weather preparations; maintenance and surveillance activities; engineering and technical support activities; followup of previously identified items; and regional requests.

Results:

Plant Operations

Operator performance during plant shutdown and startup evolutions was considered excellent. Management's decision to wait for 16 hours into a 24 hour time limit to shut down and cool down the plant before ordering the shutdown to begin resulted in the operators being placed in a position where it was very difficult for them to avoid a Technical Specification violation; however, they were able to avoid it. An operability evaluation of a reactor core isolation cooling system containment isolation valve was not considered timely. Another operability evaluation of the high pressure coolant injection system due to a failure of a condensate storage tank heat trace circuit was also not considered timely.

Maintenance and Surveillance Activities

Planning and execution of work during a short forced outage was good. There were no personnel contaminations associated with the outage work.

Engineering and Technical Support

Engineering personnel completed evaluations and resolutions of two conditions thought to be outside the design basis of the plant. One of the conditions remains an unresolved issue for the NRC.

Safety Assessment and Quality Verification

One violation and one open item were closed based on the inspectors reviews of licensee actions. Followup of regional requests determined components involved in two significant events at other plants were not used in the same applications at the Monticello plant.

DETAILS

1. Persons Contacted

Northern States Power Company

D. Antony, General Manager, Monticello Nuclear Site
M. Clarity, Assistant Plant Manager
G. Crosby, Superintendent, Quality Services
*B. Day, General Superintendent, Engineering
M. Hammer, General Superintendent, Maintenance
T. Harlan, Superintendent, Materials Engineering
*W. Hill, Plant Manager
K. Jepson, Superintendent, Chemistry
P. Johnson, Manager, Nuclear Projects
D. Nevinski, General Superintendent, Operations
J. Windschill, General Superintendent, Radiation Services

The inspectors also contacted other licensee employees including members of the technical and engineering staffs, and the reactor and auxiliary operators.

*Denotes those attending the resident inspectors' exit meeting on January 21, 1992.

2. Plant Operations

The plant operated at or near full power until a forced outage on January 2, 1992, due to failure of two safety relief valve bellows leak detectors. During the subsequent startup on January 5, the reactor was again shut down due to a problem with a low pressure coolant injection system valve. The plant was restarted later on January 5 and the turbine was placed on the grid on January 6.

a. Operational Safety Verification (71707)

The inspectors verified that the facility was being operated in conformance with the license and regulatory requirements and that the licensee's management was effectively carrying out its responsibilities for safe operation of the facility.

The inspectors verified proper control room staffing and coordination of plant activities; verified operator adherence with procedures and technical specifications; monitored the control room for abnormalities; verified that electrical power was available; and observed the frequency of plant and control room visits by station managers.

The inspectors also monitored various records, such as hold and secure card records, jumpers and bypasses, shift logs and surveillances, daily orders, and maintenance items.

All operations were considered acceptable except as noted elsewhere in this report.

(1). <u>Reactor Shutdown and Startup Observations</u>

The inspectors observed operator performance during a reactor shutdown and subsequent startup during the inspection period. Observations during the shutdown are discussed in section 2.b.(3) of this report. On January 5, 1992, operators conducted a reactor startup to the heating range. The inspectors noted that shift supervision thoroughly briefed the crew before the start of the evolution, assigned monitoring responsibilities, and insured that the proper procedures were being used during the evolution. The inspectors noted that the shutdown as well as the subsequent partial startup, shutdown, and restart were all accomplished by essentially the same crew that was involved in the shutdown discussed in Inspection Report 263/91013 and was the subject of an enforcement conference discussed in Inspection Report 263/91014. The evolutions conducted by the crew during this inspection period showed notable improvements in supervision, monitoring, and control.

After removing the shutdown cooling system from operation during the startup on January 5, one of the low pressure coolant injection (LPCI) torus suction valves did not indicate fully open causing two of the LPCI pumps to be interlocked from being able to start. The problem appeared to be with the open limit switch on the valve. Since LPCI was required to be operable before the plant was brought above 212 degrees F, the heatup was halted with the reactor critical slightly below 212 degrees. When the valve limit switch could not be immediately repaired, shift supervision ordered all control rods to be driven into the reactor rather than trying to remain in a critical condition below the point of adding heat.

A change to the operating philosophy at the plant was recently instituted which no longer allows for extended operations in Hot Standby without management approval. That change was made due to problems the nuclear industry had experienced with reactivity control in that condition. Although Hot Standby was defined as a condition with the reactor critical in the Startup mode at a power level just sufficient to maintain reactor pressure and temperature (in this case the reactor pressure was zero because the plant was below 212 degrees) shift management determined that they were in a vulnerable condition for potential reactivity management problems and made a conservative judgment to drive all control rods fully in.

The problem with the limit switch was corrected when the LPCI suction valve was exercised a few times and the plant was restarted without incident. Operator performance during the shutdown and startup evolutions was considered excellent.

(2). <u>Operability Concerns With Electrically Backseating of Motor Operated Valves</u>

On January 6, 1992, while conducting a plant heatup, packing leakage was noted on MO-2075, the inboard reactor coolant isolation cooling (RCIC) system steam supply containment isolation valve. At 12:30 A.M. operators and electricians electrically backseated the valve to stop the packing leak. At 5:45 A.M. the valve was taken off the backseat to determine if the packing leak had stopped but was then rebackseated when it was noted that the leak had not stopped. Valve MO-2075 had a history of packing leaks and had been electrically backseated routinely in past years without exhibiting operability problems. However, in the most recent refueling outage, improved packing was installed and a new, larger, motor operator was installed. The inspectors were concerned that the valve had been electrically backseated without consideration of the potential damage to the valve or effect on operability of the containment isolation function.

At 8:26 A.M. the valve was declared inoperable and the redundant outboard containment isolation valve was closed while the situation was evaluated. Problems with damage to valves due to backseating were reported by the NRC in IE Bulletin No. 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," as well as other industry information sources. The licensee had made the decision not to manually backseat valves, but had no clear policy about electrically backseating. A written procedure for electrically backseating RCIC steam supply valves was in existence but it did not address operability.

The licensee's later evaluation of valve MO-2075 concluded that backseating had not affected operability but the inspectors considered that the operability determination was untimely. Using the guidance for operability determinations provided in Generic Letter 91-18, "Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," a reasonable time for operability determination would be the Allowed Outage Time in Technical Specifications. The Allowed Outage Time for primary containment integrity in Technical Specification 3.7.A.2.a was one hour.

The licensee was issuing a revision to procedure 4 AWI-04.07.05, "General Plant Operating Activities," to require that electrically backseated valves be declared inoperable unless a preexisting evaluation was completed for determining acceptable limits of thrust and motor amperage and that the valves were backseated in accordance with a procedure that invokes the above limitations. In addition, operability will have to be demonstrated from the backseated condition by stroking the valve at least once.

(3). Switchyard Control

On December 20, 1991, the inspectors briefed the plant manager concerning two recent events involving cranes contacting offsite power lines. The inspectors provided him copies of the NRC's description of the November 15, 1991, Palo Verde Unit 3 and the December 16, 1991, Fermi Unit 2 events. The plant manager acknowledged the seriousness of the events and briefed the inspectors on the status of improvements being made to help reduce the probability of such events happening at the Monticello plant.

The licensee was making improvements to switchyard and high voltage line operations at the plant before the events listed above occurred based on the licensee's review of other industry events. The following improvements were being accomplished:

- Permanent barriers were to be installed inside the switchyard to separate areas where it was safe for vehicle travel from the areas near energized equipment and lines. Additional controls such as a requirement for shift supervisor permission and the use of a spotter will be required to use a vehicle inside the hazardous area.

- Since the permanent barrier could not be installed while the ground was frozen, a temporary barrier of rope and stanchions was installed. That work was completed on December 30, 1991. Until the ropes were in place, the shift supervisor required that a knowledgeable plant person accompany all workers in the subyard.

- Clearance bridges were installed over the roads near areas where high voltage power lines crossed. The height of the bridges was established such that vehicles that could traverse under the bridge should have sufficient clearance from the power lines such that arcing would not take place. Two new bridges were installed by January 16, 1992, and one existing bridge will be lowered to a more conservative height.

- Since much of the switchyard and high voltage work was done by non-plant NSP workers, the plant manager was pursuing methods of informing those groups about the new controls and providing refresher training on the previously existing controls.

b. Onsite Followup of Events (93702)

The inspectors performed onsite followup activities for events which occurred during the report period. These followups included reviews of operating logs, procedures, Licensee Event Reports (LERs), and interviews with licensee personnel. For each event, the inspectors developed a chronology, reviewed the functioning of safety systems required by plant conditions, and reviewed licensee actions to verify consistency with procedures, license conditions, and the nature of the event. Additionally, the inspectors verified that the licensee's investigation had identified the root causes of equipment malfunctions and/or personnel errors and that the licensee had taken appropriate corrective actions. Details of the events and the licensee's corrective actions developed through inspector follow-up are provided below:

(1). Concerns With Potential Hot Shorts During a Fire in the Control Room or Cable Spreading Room

On December 10, 1991, the licensee informed the NRC via the emergency notification system (ENS) that its review of an industry notification concerning an issue at the Susquehanna plant had determined that the same concern existed at Monticello. The issue was that under 10 CFR 50, appendix R design basis fire conditions in the control room or cable spreading room, a hot short condition could cause damage to safe shutdown valves or other components before control of the components was transferred to the alternate shutdown panel. The licensee's immediate actions consisted of declaring the alternate shutdown panel inoperable, verifying the operability of the fire detection systems and establishing hourly fire watch patrols in the cable spreading room and back-panel area of the control room in accordance with Technical Specification 3.13.H.2.c. A further discussion of the licensee's evaluation and resolution of this issue is contained in section 4.a of this report.

(2). Potential Internal Flooding Outside the Design Basis

On December 12, 1991, the licensee informed the NRC via the ENS that it had discovered the potential for internal flooding which could result in the plant being outside of its design basis. Portions of non-seismically qualified emergency service water lines and fire protection lines in the turbine building could be postulated to fail and cause flooding which could effect redundant trains of safe shutdown equipment. The licensee's immediate corrective action consisted of stationing a continuous flood watch in the area of concern until analysis and system modifications could be completed. A further discussion of the licensee's evaluation and permanent corrective action for this issue is contained in section 4.b of this report.

(3). <u>Notice of Unusual Event for a Shutdown Required by Technical Specifications</u>

On January 2, 1992, the licensee informed the NRC via the ENS that it had declared an Unusual Event and was starting a plant shutdown required by Technical Specifications. The event started at 7:30 P.M. on January 1 when the bellows leak detection alarm on the "H" safety relief valve (SRV) failed to reset fully after the performance of a surveillance. As a result, the SRV was declared inoperable for its safety valve function (self-actuation). The "G" SRV safety valve function had previously been declared inoperable due to the failure to receive the bellows leak alarm during a surveillance. In accordance with Technical Specification 3.4.E.2 if less than seven of the eight safety valve functions of the SRVs were not operable an orderly shutdown must be initiated to have reactor coolant pressure and temperature reduced to 110 psig or less and 345 degrees F or less within 24 hours.

During the night of January 1 and morning of January 2 various attempts were made to return at least one of the two SRVs to an operable status while preparations were made for an orderly shutdown. During those attempts the "G" SRV bellows leak alarm became operable but then it also failed to clear. The failure of the alarms to clear appeared to be due to leakage through solenoid valves supplying test pressure to the leak detection pressure instruments. Estimating that it would take about eight hours to shutdown the plant and reach 110 PSIG and 345 degrees, management ordered the shutdown to begin at 11:25 A.M. on January 2. The resulting Notice of Unusual Event was reported to the NRC at 11:30. The inspectors closely monitored the shutdown and subsequent plant cooldown. The licensee planned to submit LER 92-001 as a written followup for this event. The LER will remain open pending the inspectors review of the completion of all corrective actions.

During the shutdown about an hour was lost when the power reduction was halted due to concerns with exceeding the circulating water discharge rate of temperature change limit. As a result, it became obvious to the operators that there was no longer enough time to complete a normal shutdown by driving in all control rods. After the generator was removed from the grid, a manual scram was inserted to speed up the shutdown. Even with the scram, there was barely enough time to complete the cooldown within the 24 hours required by Technical Specifications while limiting the average cooldown rate to no greater than 100 degrees in each one hour period as required by Technical Specification 3.6.A.1. By maintaining the cooldown rate at approximately 95 degrees per hour, the operators were able to bring the plant below 110 psig and 345 degrees reactor coolant pressure and temperature at 7:26 P.M. (four minutes before the expiration of the 24 hour time limit) and the Unusual Event was terminated. Despite the time pressure, the operators maintained a calm, professional attitude and were able to maintain a stable cooldown rate.

Operator performance during the plant shutdown and cooldown was considered good. However management placed them in a position where it was very difficult for them to avoid exceeding a Technical Specification limit when they waited for 16 hours after the limiting condition for operation was entered before ordering the shutdown. A later evaluation of the circulating water discharge canal temperature record indicated that the cooldown rate limit of the Minnesota Pollution Control Agency had been exceeded during the plant power reduction.

(4). <u>Reactor Protection System Actuation due to Spurious Instrument Spike</u>

On January 3, 1992, the licensee reported to the NRC via the ENS that it had experienced a spurious actuation of the reactor protection system (RPS). The reactor was shut down with all rods inserted at the time so the RPS actuation did not result in any rod motion. An instrument technician was in the process of performing a test and calibration on the intermediate range monitors (IRMs) at the time. One RPS channel was in trip because of the surveillance and an IRM on the other RPS channel experienced a spurious spike. The licensee has experienced many other instances of IRM spiking during shutdown periods as reported in LERs 89-024, 89-035, and 91-010. Some of the events were believed to be due to bumping of the IRM instrument cables under the reactor vessel or other work in the drywell. In this case there was one crew working in the drywell at the time of the event but it was in the upper area of the drywell and was not believed to have caused the spike. The licensee intended to submit LER 92-002 as a written followup for this event. The inspectors will follow up the corrective actions after the LER is issued.

c. <u>Cold Weather Preparation</u> (71714)

The inspectors reviewed the licensee's cold weather preparation activities. This review included the recently performed Heat Trace Checklist (annual and monthly; Procedures 1066-1 (Rev. 1) and 1066-2 (Rev. 1) respectively, and the Winter Checklist; Procedure 1151 (Rev. 23).

No safety significant issues were noted. The performance of the annual Heat Trace Checklist performed in August of 1991 identified three unsatisfactory conditions for which work orders were generated, completed and closed. The performance of the monthly Heat Trace Checklist indicated that the south condensate storage tank (CST) vent heat trace thermostat was defective. Review of work request authorization (WRA) 91-03487 indicated the condition had been known since September 30, 1991. Discussions with the system engineer on December 19, 1991, indicated that the defect rendered the heat trace inoperable resulting in a potential to freeze the CST vent. Although it was indicated that this condition would be corrected in an expedient fashion, problems in obtaining a replacement thermostat resulted in the deficiency still not being repaired at the end of the inspection period.

The inspectors were concerned that, if the vent line froze solid, suction pressure to the safety-related high pressure coolant injection (HPCI) pump could be lost in the event of HPCI actuation. Until this was brought to the attention of engineering personnel no apparent operability assessment of the HPCI system had been done. Engineering's evaluation then concluded that the deficiency in the heat trace circuit would have no effect of HPCI operability. The following facts were used in the determination:

- The vent line was eight inches in diameter and also was insulated. In addition, the vent would not normally be exposed to water except for vapor. Thus it was unlikely that it could freeze solid.

- The failed portion of the heat trace affected only one of the two parallel CSTs.

- Twelve inch overflow lines on the tanks, located above the normal water level, could also provide venting so that suction pressure would not be lost to the HPCI pump.

The inspectors agreed that the loss of the heat trace was not safety significant; however the failure of the licensee to promptly evaluate the operability of the HPCI system until the concern was brought to the licensee's attention by the inspectors was considered an untimely operability determination.

No violations or deviations were identified.

3. Maintenance/Surveillance (61726 & 62703)

a. Work Observations

Routinely, station maintenance and surveillance activities were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes and standards, and in conformance with technical specifications.

The following items were considered during this review: approvals were obtained prior to initiating work; test instrumentation was calibrated; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; results were within specification and properly reviewed, and any deficiencies identified were properly resolved. The following maintenance and surveillance activities were observed:

Test 0002/0010	Reactor High Pressure Scram Test/Calibration
Test 0014/0043	Intermediate Range Monitor Test/Calibration
Test 0081	Individual Control Rod Scram Time Test
Test 0187-1	Emergency Diesel Generator #11 Test
WRA 92-50086	Troubleshooting Valve MO-1987 Limit Switch
Test 0003/0020	Drywell High Pressure Group II/III Isolation
Mod 91-90248	Install Keylocked RWCU High Temperature Logic Bypass Switch
Test 0278A	ATWS Test/Calibration
WRA 91-3254	Troubleshooting IRM Detector Stuck in Core
WRA 91-3274	Replace #12 Emergency Diesel Turbocharger
Mod 91-0429-0436	SRV Bellow Leak Detection Solenoid Valve Replacement

(1). Much of the work observed was during a forced outage between January 2 and January 6, 1992. In addition to the work in the field, the inspectors observed the planning, scheduling, and management aspects of the outage. In addition to the SRV solenoid problems that caused the outage, the licensee used a pre-existing ready backlog list of WRAs as the starting point for scheduling work. In case of an unexpected forced outage, the licensee maintained a ready backlog of jobs ready to work broken down into three categories; power reduction, shutdown without a drywell entry, and shutdown with a drywell entry. Depending on the expected length of the outage, the licensee selected the higher priority jobs from the ready backlog.

For the outage during this inspection period, the licensee scheduled 39 WRAs and modifications as well as several surveillance activities. Almost all of the scheduled work was done without affecting the critical path, and the outage was completed slightly ahead of schedule. Of note was that despite a great deal of work in contaminated areas, there were no personnel contaminations during the outage.

(2). For Test 0002/0010 the inspectors noted that a trainee was performing the test under the direction of an experienced technician. The experienced technician was doing a thorough job of observing and instructing the trainee.

(3). For Test 0014/0043 the inspectors observed the completion of the first IRM instrument channel. The work was being done carefully and in accordance with the procedure. Later during the remaining portion of the test a reactor protection system actuation occurred as discussed in section 2.b.(4) of this report. The actuation was believed to be due to a spurious spike and not caused by an error by the instrument technicians.

b. <u>Technical Specification Radiation Monitors Inoperable</u>

On January 7, 1992, at about 6:30 A.M., with the reactor operating in the run mode, an operations supervisor noted that the air ejector off gas radiation monitor displays in the back of the main control boards appeared to be reading too low for existing plant conditions. Chemistry personnel were notified and they checked the monitors locally and discovered that the sample suction line was flooded which rendered both monitors inoperable. The suction line was drained and the monitors returned to an operable status at about 7:00 A.M. A review of the chart recorder for the monitors indicated that the suction line probably had been flooded and the monitors inoperable since the plant startup on January 5/6.

Technical Specification 3.8.B.5.c required that the activity of radioactive material in gaseous form removed from the main condenser shall be continuously monitored by the steam jet air ejector monitors in accordance with Table 3.8.2. Table 3.8.2 required that the two channels of main condenser air ejector noble gas activity monitors be operable whenever air ejectors were in operation. The air ejectors were placed in service at 10:05 P.M. on January 5, 1992. Upon loss of both steam jet air ejector off-gas radiation monitors, the Table 3.8.2 required that the plant be in Hot Standby within six hours.

Technical Specification Table 4.8.2 required that a sensor check of the monitors be completed daily during air ejector operation. The sensor check was accomplished by operators as part of their daily control room log procedure. The sensor check was completed by logging the readings from digital exponential displays in the back of the control room, comparing them to acceptance bands, and conducting a cross check to insure that both instruments were reading approximately the same. On January 6, 1992, the readings were logged as 572 and 589 millirem per hour (mrem/hr) on the two channels. The operator believed that the displays read 5.72E2 and 5.89E2, which could have been interpreted as normal readings for the plant conditions at the time. Actually, a review of the chart recorder indicated that the displays must have read 5.72E0 and 5.89E0.

Several additional concerns were identified with this event. The inspectors noted that no log entry was made in the control room log concerning the Technical Specification monitors that were discovered to have been inoperable. A brief entry was made in the shift supervisor's log but it was not made until about twelve hours after the event. Another concern was that the minimum and maximum band indicated on the control room log was 0-3000 mrem/hr so even if the operator had logged the correct readings, they would have been within the acceptable band. A discussion with the chemistry supervisor indicated that the band was based on a wide range of possible readings from plant shutdown to full power operation with small amounts of fission product gas leakage. The chemistry supervisor also expressed a concern that the sensor check was done daily in accordance with Technical Specifications but the time limit for action required for having both sensors inoperable was only six hours. The periodicity of the sensor check did not appear to be conservative with respect to the action required for inoperable sensors. The chemistry supervisor further stated that a check of the differential pressure at the monitor, which was done shortly after the air ejectors were put on line, was unable to indicate that the suction line was flooded because the differential pressure for normal flow and a flooded line were about the same.

Licensee corrective actions to date included issuing a memorandum to operators reminding them of the expected log entries to be made in the control room log, revising the periodicity of the sensor check for the air ejector and other release path radiation monitors to four hours. Minimum and maximum reading bands on the logs were revised to more accurately reflect normal expected readings. The chemistry reactor startup checklist was revised to require that the sample suction line to the monitors be drained when the air ejectors are placed in service on each startup. The licensee intended to issue LER 92-003 as a written followup for this event.

This item will remain unresolved pending further investigation by the NRC (263/91022-01(DRSS)). No violations were identified.

4. Engineering and Technical Support (92701)

a. Potential Hot Shorts Causing a Condition Outside the Design Basis

As discussed in section 2.b.(1) of this report, as a result of licensee's operating experience assessment of events at other plants, it determined that there could be a problem during a fire in the control room or cable spreading room such that valves required for safe shutdown would not be operable when control was switched to the alternate shutdown system (ASDS) panel. The licensee postulated several examples of hot shorts which had the potential to damage equipment needed for safe shutdown. Among the postulated scenarios were a hot short that could energize a motor operated valve while bypassing the torque and limit switches such that the valve's motor operated until it was damaged, a hot short that could close the emergency diesel output breaker onto an energized bus without synchronization, a hot short that could close the offsite supply breaker onto a bus energized by an emergency diesel generator without synchronization, or an intermittent hot short that could repeatedly start and stop the motor on a valve or pump.

The licensee's evaluation of the issue determined that the plant met the requirements of 10 CFR 50, appendix R as clarified by NRC Generic Letter 86-10 in that the ASDS needed only to be able to cope with spurious actuations of all possible functional failure states of the component. The licensee interpreted "functional failure states" to mean open, closed, on, off, but not to include component damage. Based on that conclusion, the licensee retracted the 10 CFR 50.72 notification of December 10, 1991, and discontinued the fire watch patrols. At the end of the inspection period, the NRC had not determined whether that interpretation was correct.

The licensee was in the process of revising abnormal procedure C.4-C, "Shutdown Outside the Control Room," to provide guidance to operating personnel for recovering from potential hot shorts. In addition, the licensee intended to perform a failure modes and effects analysis to identify potential equipment damage from hot shorts, and to investigate options to correct concerns and determine the feasibility of implementing them.

The inspectors submitted documents concerning this issue to the NRC Office of Nuclear Reactor Regulation (NRR) for further review. Since the acceptability of the licensee's ASDS design may depend in part on an interpretation of 10 CFR 50, appendix R that is open to question, this issue is considered an unresolved item pending resolution by NRR. (263/91022-02)

b. Internal Flooding Concern

As discussed in section 2.b.(2) of this report, the licensee discovered additional areas of concern as part of its internal flooding design basis documentation efforts. Previous similar concerns were discussed in Inspection Report 263/91016, section 2.b.(3) and LER 91-018, revisions 0 and 1. In this case the concerns were with two three-inch emergency service water discharge lines from the emergency filtration system, one four-inch fire protection line and a standpipe on the demineralized water storage tank. The lines were all non-seismically qualified and located in an area of the turbine building where failure could result in loss of redundant safe shutdown equipment.

The licensee's analysis of the pipes determined that the emergency service water lines would not supply sufficient flow in the event of failure to be a concern. The fire protection line was determined to meet operability requirements and was made to meet seismic qualification requirements with a minor alteration to one hanger. In addition, the licensee determined that had the fire protection line failed, alarms in the control room would have given operators sufficient time to discover and isolate the leak before both trains of safe shutdown equipment could be affected. The demineralized water tank standpipe concern was resolved when calculations showed that the entire volume of the tank could be emptied into the area of concern without affecting both trains of safe shutdown equipment. As an additional precaution, the licensee changed the operating procedures to limit the level in the tank to a lower value so that the volume of water released in case of a rupture would be even less of a concern.

The licensee intended to submit revision 2 to LER 91-018 to report the findings. The LER will remain open pending completion of any remaining corrective actions.

No violations or deviations were identified. One unresolved item was identified.

5. Safety Assessment/Quality Verification

a. Followup of Previously Identified Items (92701)

(I) (Closed) Violation 263/89014-0I: RCIC Inoperability

This violation was previously discussed in Inspection Report 263/89014. It involved the inoperability of the reactor core isolation cooling (RCIC) system for longer than allowed by Technical Specifications due to an inadequate testing procedure. The licensee revised and approved Procedures 7140 (Rev. 7) 5/11/89 and 7130 (Rev. 6) 5/11/89, to perform the system operability tests after the completion of the level switch test and to limit the time in which the steam line drain was closed. Maintenance and Surveillance Procedures 0149, Rev. 4, 1052-1, Rev. 1, 1080, Rev. 6, and 7202, Rev. 1, were revised and approved to ensure that systems were not declared operable prior to completing the test and time limits were provided to avoid similar situations. In addition, Revision 4 to 4 ACD 15.03, "Procedure Content," approved on 8/31/89 provided for additional instructions on preparing maintenance and surveillance procedures. LER 89-006 was added to the fourth quarter 1989 Engineering & Technical Staff training Lesson Plan M7503L-003 "Operating Experience". Lessons learned from this event including impact of testing on equipment operability were covered in Lesson Plan M9213-A-013 in the Licensed Operator Continuing Training Program. And finally a weekly review by plant management of all safety-related equipment work request authorizations was initiated 7/21/89 and was continuing at present.

All licensee commitments have been completed/resolved for this issue and it is considered closed.

(2). <u>(Closed) Open Item 263/91017-03: Diesel Generator Turbocharger</u>

This issue was previously discussed in Inspection Reports 263/910II, section 4.d, and 263/91017, section 5.c. The issue remained open pending the inspectors' review of the vendor's failure analysis of the turbocharger from the #11 emergency diesel generator (EDG) and consideration of the licensee's plan for replacing the turbocharger on the #12 EDG if warranted. As discussed in section 3.a of this report, the turbocharger on the #12 EDG was replaced with an improved model for which failure of the overrunning clutch due to low load operation should not be a concern.

The vendor's analysis of the failed turbocharger showed that it was due to normal wear and no unusual mechanisms were noted. The system engineer had started tracking the hours of operation at low load on the #11 EDG since the turbocharger was replaced, so that the turbocharger can be replaced again before accumulating enough hours to cause likely failure. It was the intention of the licensee to replace the turbocharger on the #11 EDG with the improved model in the future. This item is considered closed.

(3). (Closed) LER 90-001, revision 2, and (Open) LER 90-001, revision 3: Potential Emergency Filter Train System Inoperability Due to Interaction with Non-Safety Related Equipment

As discussed in Inspection Report 263/91018, section 5.a, the licensee submitted a revision to LER 90-001 documenting a new concern with the emergency filtration train system. The previous revision is considered closed to reduce duplication of tracking. Corrective action commitments in the revised LER include all those from the previous revisions and will be inspected when they are completed.

(4). (Closed) LER 91-012, revision 0, and (Open) LER 91-012, revision 1: Improper Fuse Setting and Wire Error Causes Unplanned Emergency Filtration Train Actuation

This event was originally discussed in Inspection Report 263/91007, section 2.c.(10). During this inspection period the licensee issued a revision to the original LER with additional information on the cause of the event and corrective actions. The original LER is closed to reduce duplication of tracking. The corrective actions will be inspected when completed.

b. Followup of Regional Requests (93700)

(1). Concern With Parker Solenoid Valves

In response to a request by regional management to follow up an event which occurred at Salem Unit 2, the inspectors were asked to determine the extent that Parker solenoid valves were used at the site. The inspectors contacted the superintendent of materials engineering who determined that the only application of Parker solenoid valves at Monticello was in the radioactive waste system where a failure would not be as critical as the ones that failed in the turbine overspeed protection system at Salem.

(2). Concern With Compression Fittings

In response to a request by regional management to follow up an event which occurred at Oconee Unit 3, the inspectors were asked to determine whether the licensee used compression type fittings on piping systems that could not be isolated from the reactor. The inspectors discussed the issue with the general superintendent of maintenance and were informed that he had already looked into the issue based on his review of industry events. The General Electric design specification for instrument piping attached to the reactor coolant system and located inside containment required that all fittings be welded. The general superintendent of maintenance was aware of no fittings which did not meet that specification. He stated that the only compression fittings used on lines attached to the reactor coolant system were outside the containment and downstream of the excess flow check valves and were therefore isolable from the reactor.

No violations or deviations were identified.

6. Exit Interview

The inspectors met with the licensee representatives denoted in Paragraph 1 at the conclusion of the inspection on January 21, 1992. The inspectors summarized the purpose and scope of the inspection and the findings. The inspectors also discussed the likely informational content of the inspection report, with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.