U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-263/91011(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: May 31 through July 15, 1991

Inspectors: S. Ray

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Reactor Projects Section 2B

JUL 24 1991
Date

Inspection Summary

Inspection on May 31 through July 15, 1991 (Report No. 50-263/91011(DRP))

Areas Inspected: A routine, unannounced inspection by the resident and regional inspectors of operational safety verification; onsite followup of events; radiological controls; maintenance and surveillance activities; followup of previous inspection findings in engineering and technical support; licensee event reports; regional requests; and assessment of setpoint methodology.

Results:

Plant Operations

Although plant operators responded to operational events properly and conservatively, weaknesses were noted in the control of reactor startup and shutdown activities. The shutdown activities were the subject of a separate inspection.

Radiological Controls

The licensee's discovery of an unattended, inadequately locked door to a high radiation area, soon after corrective actions to previous similar events were implemented, resulted in an unresolved item for which a licensee response was requested.

Maintenance and Surveillance Activities

Strengths were noted in instrument and controls personnel knowledge and skill levels. Additionally, the planning and execution for the replacement of an emergency diesel generator turbocharger were excellent and included significant management involvement.

Engineering and Technical Support

The licensee's response to self-identified electrical cable separation issues was generally considered conservative and timely. However, a violation was identified in that one deficiency was not promptly corrected due to inadequate documentation and communication of the finding. An additional weakness was noted in that the licensee failed to properly coordinate two relays in a recent modification to the 2R transformer.

Safety Assessment and Quality Verification

A weakness was noted in the setpoint determination methodology and assessment of the effects of setpoint drift in emergency diesel generator base tank level switches.

DETAILS

1. Persons Contacted

L. Eliason, Vice President, Nuclear Generation
D. Antony, General Manager, Monticello Nuclear Site
K. Albreckt, Director, Power Supply Quality Assurance
G. Crosby, Superintendent, Quality Services
*B. Day, General Superintendent, Engineering
M. Hammer, General Superintendent, Maintenance
#*W. Hill, Plant Manager
G. Hudson, Superintendent, Security
P. Johnson, Manager, Nuclear Projects
P. Kamman, Manager, Nuclear Operations Quality Assurance
D. Nevinski, General Superintendent, Operations
T. Parker, Manager, Nuclear Support Services
R. Scheinost, General Superintendent, Site Services
J. Windschill, Superintendent, Radiation Protection

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

#Denotes those attending the management meeting in the Region III office on July 10, 1991.

*Denotes those attending the resident inspectors' exit meeting on July 15, 1991.

2. Plant Operations

The plant was synchronized to the grid following a refueling outage on May 31, 1991. A plant trip from full power occurred on June 5. During the subsequent plant startup on June 6, a leaking safety relief valve caused plant management to decide to shut down for repairs. During that shutdown, the reactor tripped on high-high intermediate range monitor signals while the monitors were in range seven. The reactor was restarted on June 8 and operated at or near full power for the remainder of the inspection period.

a. Operational Safety Verification (71707)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection period. During these discussions and observations, the inspectors ascertained whether the operators were alert, cognizant of plant conditions, attentive to changes in those conditions, and took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. Tours of the plant were conducted to observe equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations, and to verify that maintenance requests had been initiated for equipment in need of repairs.

The inspectors verified by observation and direct interviews that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. The inspectors also witnessed portions of the radioactive waste system controls associated with radwaste shipments and barreling.

(1) The inspectors closely observed the reactor startup of June 8, 1991 because of problems identified previously with management oversight of control room activities (Inspection Report 263/91013). In this case, management of oversight was improved but still had some weaknesses. Before the startup, the shift supervisor instructed the reactor operator to read the startup procedure and its precautions. The inspector also noted that the appropriate procedures were out and being used in the startup; the shift supervisor closely observed the reactor operator's actions and the response of instrumentation during the approach to criticality; and the reactor operator had adequate help from other control room personnel. However, during a shift turn over that occurred in the middle of the approach to criticality, the reactor operator continued to withdraw control rods while all of the other shift control room personnel were going through the turn over process.

In addition, after the reactor reached criticality, the oversight of the reactor operator's performance was significantly reduced even though he was involved in taking the reactor up through the intermediate range to the heating range, an evolution requiring a significant amount of concentration. These observations were discussed with operations management.

(2) The inspectors observed the operator's response to the loss of one of the recirculation pumps on July 8, 1991. The cause of the pump loss is discussed in section 4.e of this report. The operators were observed to use and follow the established procedures for loss and recovery of the pump. Shift supervision closely monitored the performance of the operators and insured that all applicable precautions were followed. The operators were aware of and attentive to possible core oscillation problems in single loop operations. The tripped recirculation pump was restarted within 41 minutes after the loss.

b. Onsite Follow-up of Events (93702)

The inspectors performed onsite follow-up activities for events which occurred during the report period. These follow-ups 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) On June 1, 1991, with the plant at 90% power, a partial group II containment isolation and standby gas treatment system initiation occurred. The cause of the event was determined to be loss of power to the spent fuel pool and reactor building exhaust plenum radiation monitors due to tripping of a reactor protection system motor generator set. The licensee properly reported the event to the NRC via the Emergency Notification System (ENS) in accordance with 10 CFR 50.72 and issued LER 91-013 as a written followup. The event was considered significant only to the extent that it resulted in an unanticipated actuation of engineered safety systems. The LER will remain open pending completion of the corrective actions. The event was discussed further in section 4.b of this report.

(2) On June 5, 1991, the licensee experienced a reactor trip from 100% power. The cause of the event was a spurious trip of the "A" main steam line isolation channel while the "B" channel was in the tripped condition for a surveillance. All equipment operated normally after the trip and the operators' post trip actions were observed by the inspectors to be correct. The reactor feed pumps tripped during the event and when one of the pumps was subsequently restarted, the discharge check valve on the other pump slammed shut loudly. The licensee properly reported the trip to the NRC via the ENS and issued LER 91-014 as a written followup.

    The inspectors followed the licensee's evaluation of the cause of the trip. Although the exact cause of the spurious trip was not determined, the inspectors determined that all reasonable efforts were applied in an attempt to find it. In addition, the feedwater check valve that had slammed shut was disassembled and inspected, and the feedwater lines were walked down to look for damage to supports prior to the subsequent startup. No damage was found. The surveillance activities that may have contributed to this event are discussed in section 4.c of this report. The LER will remain open pending completion of the corrective actions.

(3) On June 6, 1991, with reactor power at level seven in the intermediate range, the reactor tripped while conducting a shutdown. A regional inspector was in the control room at the time of the event and observed the immediate actions. The licensed operators' response to the trip was adequate. The event was properly reported to the NRC via the ENS and LER 91-015 was issued as a written followup. This event was the subject of a separate inspection documented in Inspection

Report 263/91013 and Enforcement Conference Report 263/91014. In addition, an evaluation was conducted by the NRC Office for Analysis and Evaluation of Operational Data. Their report was not yet issued at the conclusion of this inspection. The LER will remain open pending completion of the corrective actions.

(4) On July 6, 1991, during the quarterly high pressure coolant injection (HPCI) pump operability test, pump differential pressure was found to be high in the action range of the American Society of Mechanical Engineers, Section 11 requirements. Pump flow was normal and the pump could have met its design basis requirements but it was declared inoperable until the test was successfully repeated later the same day. The licensee reported the event to the NRC via the ENS but later retracted the notification when an investigation determined that the first test failure was due to misreading of the instrumentation resulting in setting the pump speed somewhat high. The inspectors had no remaining concerns about HPCI pump operability.

No violations or deviations were identified.

3. Radiation Controls (71707)

On June 25, 1991, a licensee radiological controls technician discovered that an unattended door controlling access to a high radiation area with a dose rate exceeding 1000 mrem/hr was not adequately secured. The door was in a fence around the turbine. It was found to be locked but the locking mechanism was not properly engaged and the door came open when pulled on by the technician who was conducting a routine inspection of locked high radiation doors. Technical Specification 6.5.B.1.c required that doors to areas with intensities of radiation greater than 1000 mrem/hr be locked or attended. Inadequate controls of high radiation doors was the subject of a recent non-cited violation (263/91005-01) and a cited violation (263/91008-02). As a result of this latest event the licensee has made additional corrective actions beyond those discussed in the previous violations, including requiring independent verification by radiological controls personnel before a user leaves a locked high radiation door. In addition, the licensee was evaluating closure mechanisms or annunciators on the doors. This latest event which appears to be an isolated mechanical problem, is considered an unresolved item (263/91011-01).

One unresolved item was identified.

4. Maintenance/Surveillance (61726 & 62703)

Station maintenance and surveillance activities of the safety-related systems and components listed below were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while affected components or systems were removed from and restored to service; approvals were obtained prior to initiating work or testing; quality control records were maintained; parts and materials used were properly certified; radiological and fire prevention controls were accomplished in accordance with approved procedures; maintenance and testing were accomplished by qualified personnel; test instrumentation was within its calibration interval; functional testing and/or calibrations were performed prior to returning components or systems to service; test results conformed with Technical Specifications and procedural requirements and were reviewed by personnel other than the individual directing the test; any deficiencies identified during the testing were properly documented, reviewed, and resolved by appropriate management personnel; work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance. The following maintenance and surveillance activities were observed:

- WRA 91-01507 - Troubleshoot stack wide range gas monitor mid-range detector.

- WRA 91-02910 - Replace #11 emergency diesel generator turbocharger.

- WRA 91-02966 - Troubleshoot scram relay 5A-N13E.

- WRA 91-50054 - Troubleshoot/repair trip of RPS MG set output breaker.

- WRA 91-50056 - Investigate cause of digital feedwater control problems.

- Test #0002/0010, "Reactor High Pressure Scram Instrument and Calibration Procedure."

- Test #0034, "Valve Permissive Sensor Test."

- Test #0035, "Valve Permissive Sensor Calibration."

- Test #0051, "Main Steam Line High Flow Group I Isolation Instrument Test and Calibration."

- Test #0054, "Main Steam Line Low Pressure Group 1 Isolation Instrument Test and Calibration."

- Test #0278a/0282a, "ATWS-Recirc Trips for Reactor Pressure and Level Trip Unit Test and Calibration."

a. The inspectors observed that some maintenance activities and troubleshooting work request authorizations (WRAs) did not provide details of work actually accomplished or parts replaced. However, the inspectors noted that the troubleshooting activities were adequate and accomplished by skilled instrument and controls (I&C) technicians. In addition, the inspectors noted that I&C surveillances were performed in accordance with procedural requirements. The I&C supervisor and craft were knowledgeable, dedicated and adequately trained. The knowledge and skill of the I&C staff was considered a strength.

b. On June 1, 1991, the licensee was performing the APRM weekly functional test. During the test, the "A" Reactor Protection System - Motor Generator (RPS-MG) set tripped and caused a group II isolation and standby gas treatment system (SGTS) initiation. The licensee determined that the nonsafety-related output breaker to the RPS-MG set had tripped. The licensee issued work request authorization (WRA) 91-50054 to replace the breaker; however, during testing the breaker tripped again. The licensee subsequently discovered that the overvoltage relay (also not safety-related) which had a trip set point of 135v had drifted down to about 122v. The 122 volts was the normal operating voltage for RPS-MG sets. The relay was calibrated and the post maintenance test was adequate.

In response to questions by the NRC inspectors, the licensee determined that the overvoltage relays on both RPS-MG sets had not been calibrated since 1982. The licensee elected to wait to test the overvoltage relay on the redundant "B" RPS-MG until the next scheduled semiannual surveillance on the unit because of the risk associated with transferring power from the RPS-MG to the alternate power supply. Additionally in the LER reporting this event (LER 91-013) the licensee committed to evaluate the need for periodic maintenance on other RPS-MG set components and evaluate the possibility of transferring the power supplies for the radiation monitors to a more reliable source. The general superintendent of engineering also stated that the licensee was in the process of compiling a list of "critical" balance of plant equipment and evaluating maintenance practices on that equipment.

c. While observing Test #0054 on June 5, 1991, a regional inspector witnessed portions of the calibration of the steam line low pressure isolation sensors located in the turbine building. The inspector was satisfied that the I&C technician was knowledgeable in the use of the procedure and the inspector left shortly after the technician completed one of the four instruments. However, a reactor scram occurred shortly after the inspector left. The scram was caused because the group I isolation channel B2 test switch was in the trip position per the test procedure when a second channel tripped making up the scram isolation logic. As reported by the licensee in LER 91-014, the licensee had not determined the reason for the second channel tripping but the inspector was satisfied that the test procedure in progress at the time was being done properly.

d. On July 1, 1991, during performance of the monthly operability test on the #11 emergency diesel generator (EDG), the licensee experienced problems with the turbocharger which resulted in the diesel being declared inoperable. The licensee determined that the turbocharger would have to be replaced. A replacement was not available on site and had to be obtained from a vendor. The licensee also determined that the turbocharger unit was large enough that there was doubt that it could be brought into the room without great difficulty. Because of those potential problems and the upcoming holiday, the licensee made preliminary contacts with the NRC concerning a potential need for a waiver of compliance if the diesel could not be repaired within the seven day time allowed by Technical Specifications.

The inspectors closely followed the efforts to obtain a replacement part and move it into the room. It was determined that the safest and most practical way to get the old turbocharger out and the new one in was to move them through the #12 EDG room. This raised the possibility that an accident while moving the large parts could disable the #12 EDG. The licensee discussed its plans with the NRC on July 3. The licensee took measures to protect the #12 EDG and the integrity of offsite power sources during the moves. The inspectors reviewed the planned movements in detail with the licensee. The inspectors noted that senior plant management and industrial safety personnel were involved in planning the moves. The inspectors observed both the removal of the old turbocharger and the arrival of the new one. The licensee's planning of the evolution was excellent and the moves were executed with few problems. The #11 EDG was repaired and returned to service on July 4 so a waiver of compliance was not needed.

e. On July 8, 1991, while electricians were performing minor maintenance on a running recirculation pump motor generator (MG) set, the MG set tripped due to loss of excitation field causing loss of one recirculation pump. The electricians had been straightening out the wires to the excitation brushes at the time of the event. The wires had apparently been bent where they exited their holders during the last refueling outage. The licensee was concerned that the bent wires could prevent the brushes from maintaining contact with the rotor slip rings as the brushes wore down in operation. The licensee decided to attempt to straighten the wires with the MG sets operating because it was thought to hold less risk than securing them one at a time and operating in single loop. There were a total of eight sets of wires to be straightened. Proper precautions for working on energized electrical equipment were being followed. As the electrician completed the last of the eight sets of wires, his glove apparently caught on a wire and caused it to contact a wire from a brush of the opposite polarity. That caused the circuit to sense a loss of excitation and trip the MG set.

The inspectors considered the trip to be an isolated maintenance error and not indicative of a program weakness. The licensee had previously evaluated and discontinued the practice of changing brushes while the MG sets were operating and, after this event, a precaution was added to the operations manual section on recirculation pumps to allow only passive inspections of the brushes during MG set operation.

f. The licensee has experienced a number of reactor trips and engineered safety feature actuations during surveillance testing. Many of the events occurred when one instrument channel trip system was intentionally placed in the tripped condition during the surveillance and a spurious trip occurred on a channel in the other trip system (it has been the licensee's practice to intentionally trip the instrument channel trip system under surveillance). The licensee discussed this practice with the inspectors and the acceptability of entering the Technical Specification Limiting Condition for Operation (LCO) for instruments under test but not inserting an intentional trip. The NRC noted that such practice is not prohibited by the technical specifications and therefore did not disagree with the licensee discontinuing the practice of placing trip systems in trip during surveillances provided that the applicable LCOs are entered and the associated action statements are followed within the specified times.

Technical Specification LCOs allow most instruments to be inoperable for a designated amount of time before action must be taken to place the trip system in trip or enter a plant condition for which the instrument function is not required. The inspectors also reviewed NUREG-1422, Vol.1 (Draft Report for Comment), "Standard Technical Specifications, General Electric Plants, BWR/4," which generally would allow placing one instrument channel in an inoperable status for up to six hours for required surveillance without placing the associated trip system in trip, provided at least one OPERABLE channel in the same trip system is monitoring that parameter. The licensee intends to pursue an amendment to the Technical Specifications to clarify the issue and allow conducting surveillances without placing the trip system in trip or entering an LCO action statement.

No violations or deviations were identified.

5. <u>Engineering and Technical Support/Followup of Previous Inspection Findings</u> (92701)

a. The inspectors reviewed actions taken by the licensee to identify and resolve previously identified electrical separation issues. In general, electrical cables of redundant safety systems must be physically separated so that a single event such as a fire, short, or flying debris does not cause the loss of both subsystems. On April 27, 1991, the licensee determined that cables for the secondary containment isolation damper solenoids and standby gas treatment system (SGTS) did not meet separation requirements. These examples violated separation requirements stated in the Updated Safety Analysis Report (USAR) and on controlled drawings. The licensee discussed the findings and intended actions with the NRC in conference calls on May 13 and 14. In the conference calls, the plant manager verbally committed to complete walkdowns of the reactor protection system and emergency core cooling systems that were not previously inspected for separation. On May 28, 1991, the licensee issued licensee event report (LER) 91-009 which detailed the findings and corrective actions for the separation issues. On the same date, another conference call was held between the licensee and the NRC. The licensee discussed actions that were taken and evaluations to resolve existing separation problems. The licensee presented results which indicated that none of the remaining issues would prevent any system from performing its safety function for design basis accidents. The licensee committed to correct or evaluate the separation problems before plant startup.

The inspectors reviewed corrective action and records of the licensee's walkdowns of the primary containment isolation system (PCIS), emergency core cooling system (ECCS), reactor protection system (RPS) and the secondary containment, cable spreading room areas and the standby gas treatment systems (SGTS) rooms. The license's walkdowns were comprehensive and identified a number of separation problems. With the exception of one example (discussed below) concerning inadequate separation of the off gas dilution fans, the licensee's corrective actions and/or evaluations were conservative and timely. Many of the problems identified by the licensee concerned lack of separation between redundant alarm or indication circuits and consequently, were not safety significant.

The more significant problems such as lack of separation between the division 1 and division 2 cables, associated with the reactor building isolation damper solenoids, were corrected prior to declaring secondary containment operable. The licensee also found that 11 outboard isolation valves/pilot solenoid valves were routed in the same raceway. The licensee evaluated the circuitry to ensure that the system met the licensing basis for single failure criteria. Pages 7.1-1 and 8.8-1 of the licensee USAR stated that separation was not necessarily provided for power circuits where the particular system was such as to be fail-safe for loss of power. Although the PCIS was not necessarily required to be separated, the licensee committed to reroute the cables during the next refueling outage. In the cable spreading room, the licensee performed a limited walkdown to verify separation. However, the licensee committed to inspect the cable spreading room during subsequent refueling outages using a signal tracer and also during future cable pulls. In addition, the cable spreading room met the Appendix R requirements for safe shutdown and consequently, the risk due to separation problems was minimal.

The inspectors reviewed drawings and performed an independent walkdown of the areas inspected by the licensee to determine if the licensee had separated the cables where mandatory separation was required. The inspectors did not identify any separation problems or examples where the licensee deviated from the design drawings.

As mentioned above, the licensee previously identified inadequate cable separation between flow switches in the off-gas dilution fan controls. The licensee found that cables for PS-8000-J15 (A train) and PS-8000-J16 (B train) stack low air flow switches were routed in a common raceway from the off-gas stack into the plant, a distance of several hundred feet. The two flow switches which were part of the SGTS started the off-gas dilution fans during low flow conditions. The fans are required in some situations so that the safety-related standby gas treatment system can meet its design basis flow in order to maintain specified negative pressure in the secondary containment.

The licensee's drawings E-109, sheet 22 and E-109, sheet 23 required mandatory separation between the two divisions of SGTS. In addition, Technical Specification 3.7.B.1.a required that two separate and independent SGTS shall be operable at all times when secondary containment integrity was required or enter a seven day limiting condition for operation (LCO). The licensee discovered the problem on or about May 10, 1991, and management believed that the problem had been corrected prior to plant startup on May 31. However, on June 10, 1991, a system engineer performing a walkdown noted that the problem had not been corrected. Apparently, due to inadequate documentation and communication of the original discrepancy, the problem had been misunderstood and the licensee's corrective action performed a modification of two other switches in close proximity to the unseparated ones. On June 10, after the inadequate corrective action was discovered, the licensee took action to meet the separation requirements by disconnecting the leads to flow switch PS-8000-J16 which eliminated the automatic function of the B train dilution fan. This caused the B train to operate in manual continuously and the A train to be placed in automatic in order to maintain the off-gas dilution A train in standby. The licensee completed the temporary modification on June 13 and exited the LCO. The licensee planned to reroute the cables during the next outage.

Although the licensee identified the initial separation problem, incorrect corrective action was taken in part because the walkdown sheets used to identify separation problems were not made part of the modification package. Additionally, subsequent licensee reviews to correct or evaluate this example did not identify the problem. 10 CFR 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality, deficiencies, deviations and nonconformances are promptly identified and corrected. Failure to take prompt, adequate corrective action is considered a violation of 10 CFR 50, Appendix B, Criterion XVI (263/91011-2(DRP)).

b. On May 24, 1991,the licensee informed the NRC of an engineered safety features (ESF) actuation of the control room ventilation - emergency filtration system (EFT) (LER 91-012). The cause of the event was a momentary loss of power to the EFT control logic when the 2R transformer tripped. The transformer tripped after a current limiting fuse actuated and caused a phase imbalance and ground fault which tripped the 2R transformer. The event itself was considered significant only to the extent that it resulted in an unnecessary actuation of an engineered safety system.

The inspector reviewed the circumstances surrounding the trip of the 2R transformer. The inspector noted that the licensee did not identify, during motor starting current calculations and post modification testing, that the current limiting protector (CLP) fuse was not set to trip at the value specified by the vendor. In addition, the licensee did not perform an adequate coordination study between a newly installed phase imbalance relay and the existing ground fault relay.

During the last refueling outage, the licensee had performed a modification which installed current limiting reactors, a CLP fuse/firing unit assembly and a phase imbalance relay on the 34.5kv side of the 2R transformer. The modification was performed under modification request 907042. The licensee originally requisitioned CLP assemblies which would trip at approximately 2800 amps (peak current). The manufacturer delivered CLP units with documentation that indicated that the CLPs were rated at approximately 2500. During post modification testing of the CLP, the licensee used values supplied by the manufacturer. The licensee assumed that these values which were in the range of 30-50 charging volts corresponded to the trip set point of 2500 amps. However, the licensee had not consulted with the manufacturer to determine whether the supplied voltage values corresponded to 2500 amps.

After the trip of the 2R transformer, the CLP units were sent back to the manufacturer. The manufacturer determined that the firing units were actually set at approximately 1900 amps. Consequently, the licensee determined that the starting current of the reactor feedwater pump motor approached the set point of the CLP fuse causing the fuse to blow. The licensee indicated that the fuse setpoint did not provide adequate margin for the starting transient of the 6000 horsepower reactor feedwater motor.

Although the CLP fuse was not sized properly, an orderly transfer should have occurred between the fuse to the current limiting reactors. If coordinated properly, the phase imbalance relay should have transferred the flow of current from the fuse to the current limiting reactors without tripping the 2R transformer. Instead, because the ground fault relay was not coordinated with the phase imbalance relay, the ground fault relay tripped the 2R transformer before the phase imbalance relay actuated. In the licensee's safety evaluation the question of coordinating the two relays was not addressed. Failure to adequately coordinate the relays was considered a weakness.

One violation was identified.

6. <u>Safety Assessment/Quality Verification</u>

a. <u>Licensee Event Report (LER) Follow-up</u> (90712 & 92700)

Through direct observation, discussions with licensee personnel, and review of records, the following LERs were reviewed to determine that the reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications. Based on the inspectors' review, the following LERs are closed:

(1) (Closed) LER 90-018: Spurious Reactor Protection System Actuation Caused by Mode Switch.

This item was previously discussed in Inspection Report 50-263/90022. The event was similar to other reactor protection system (RPS) actuations caused by poor operation of the reactor mode switch such as LERs 88-008 and 89-037. During the 1991 refueling outage the mode switch was replaced by one with an improved design developed by the Boiling Water Reactor Owners Group. A discussion of the licensee's discovery and corrective actions for a logic problem with the new switch was contained in Inspection Report 50-263/91007. During post modification testing and the subsequent reactor operation since the refueling outage the switch has performed well. This item is considered closed.

(2) (Closed) LER 90-019, Supplement 1: Potential Loss of Fuel Oil Transfer Capability During External Flooding Due to Procedural Inadequacy.

This item was previously discussed in Inspection Report 50-263/90026, section 6.a.(1). The licensee issued supplement 1 to the LER on April 24, 1991, after the original LER was closed. The supplement discussed additional concerns with flood protection of vital equipment that were found by the licensee during a design basis document field walkdown. Those concerns included floor drains, equipment drains, electrical conduits, and other penetrations that were located below the level of the maximum probable flood and not identified for protection in the external flooding procedure. The cause of the procedural inadequacies was attributed to an incomplete external flooding study performed by the architect-engineer during initial plant licensing. The inspectors verified that compensatory actions to address the additional concerns were added to the flood procedure. This item is considered closed.

(3) (Closed) LER 91-009 and (Open) LER 91-009, Supplement 1: Inadequate Control of Construction Activities Causes Failure to Meet Cable Separation Requirements.

On June 28, 1991, the licensee issued Supplement 1 to LER 91-009 detailing the information on the electrical separation problems that were discovered subsequent to the original LER. The original LER 91-009 is considered closed and corrective actions will be tracked with the supplement.

b. Follow-up of Regional Requests

(1) In response to a request from regional management as part of an NRC Office for Analysis and Evaluation of Operational Data study, the inspectors supplied information concerning the licensee's actions to minimize shutdown risk. The questions concerned removal of the residual heat removal suction valve auto-closure interlocks and making Technical Specification requirements for decay heat removal redundancy more conservative. The inspectors reported that the licensee had no plans to change its RHR system or specifications at this time. The inspectors

provided additional information about the licensee's practices instituted during the last refueling outage to maintain the availability of offsite power sources and redundant core cooling systems beyond the requirements of Technical Specifications. This practice was discussed in previous inspection reports and was considered a good practice.

(2) In response to a request from regional management the inspectors provided information about the licensee's practices and control mechanisms for voluntary entry into Technical Specification Limiting Conditions for Operations (LCOs) to perform elective corrective or preventative maintenance. It has generally been the licensee's practice in the past to avoid voluntary LCO entries but that philosophy is being reevaluated.

c. Setpoint Methodology Assessment

The inspector noted that the setpoint methodology and resolution for the diesel generator (DG) base tank level switches was less than adequate. In October 1990 the licensee issued nonconformance item (NCI) report No. 90-043 to resolve problems with out of calibration base tank level switches LS-7211 and LS-7215 associated with the 12 (division 2) DG. These level switches tested under surveillance test procedure #1052 started the respective #1 and #2 fuel transfer pumps from the day tank to the base tank. A review of the NCI indicates that level switches were out of calibration since 1986 and possibly as early as 1982. However, no tolerance was specified before 1986 (a 15% tolerance was established in 1986). In addition, the inspectors found that no evaluation was performed on the instruments out of calibration status. Furthermore, the current level switch setpoints differed from the manufacturer's recommended values and the operations manual and between each DG.

The inspector reviewed the NCI and found that the licensee accepted the present level switch setpoints as use-as-is. This was based on the proper sequence in starting the fuel transfer pumps and that additional starts would not be detrimental to the pumps. No basis was given as to where the previous tolerance of 15% and the present tolerance of 4-10% was derived. The inspectors also found that the licensee did not have a procedure or instructions on how the level switches were to be adjusted. Moreover, there was no documented evidence that level switches have ever been adjusted. The present setpoints were the latest as-found values. Furthermore, associated with the 11 DG (division I) there was no documented evidence that the high level reset of switch LS-7212 was ever tested. The licensee's testing procedures (past and present) did not require calibration of the reset setpoint.

Failure of level switch LS-7212 to properly reset would have prevented the start of both fuel transfer pumps. The inspector did not find an example where the level switch had failed to reset. However, the inspectors considered the setpoint evaluation and lack of adequate procedures to test the reset function to be a weakness.

The general superintendent of engineering stated that training on setpoint methodology was being added to the engineering continuing training program.

d. Management Meeting

On June 10, 1991, a management meeting was held at the Region III office between Mr. L. Eliason, Vice President, Nuclear Generation and members of his staff and Mr. A. B. Davis, Regional Administrator and members of his staff. Licensee attendees were designated in section 1 of this report. At the meeting the licensee discussed actions taken in response to recent industrial safety events, NRC inspections, operational issues, and radiation protection issues. The licensee also discussed its plans to improve plant procedures.

No violations or deviations were identified.

7. Unresolved Items

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An Unresolved Item disclosed during the inspection was discussed in section 3.

8. Exit Interview

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on July 15, 1991. 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.