U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-263/91007(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: April 16 through May 31, 1991

Inspectors: S. Ray

P. Moore

K. Riemer

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

JUN 07 1991
Date

Inspection Summary
Inspection on April 16 through May 31, 1991 (Report No. 50-263/91007(DRP)
Areas Inspected: A routine, unannounced inspection by the resident inspectors of operational safety verification; outage activities; onsite followup of events; engineered safety feature system walkdown; maintenance and surveillance activities; engineering and technical support; followup of previous inspection findings; licensee event reports; and regional requests.

Results:

Plant Operations

Strengths were noted in control of work activities and equipment availability to minimize shutdown risk. Management was closely involved in those efforts. Ten events requiring notification of the NRC via the Emergency Notification System occurred during the inspection period. Some of these events were significant as indicated in the report. All notifications were timely and correct.

Maintenance and Surveillance Activities

Extensive maintenance and surveillance activities took place during the inspection period due to the refueling outage. All observed activities were

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performed correctly. Involvement of first line supervisors in maintaining industrial safety was considered a weakness.

Engineering and Technical Support

Engineering efforts to resolve issues involving cable separation, control rod drive cap screws, and mode switch logic were considered good. Proper attention was paid to reactor safety in those resolutions. All the issues were licensee identified. The licensee's discovery and innovative resolution of the logic problem with the mode switch was considered especially commendable.

Safety Assessment and Quality Verification

The licensee demonstrated conservative judgement in resolving safety issues which came up during this inspection period. Management was actively involved in evaluating those issues.

DETAILS

1. Persons Contacted

D. Antony, General Manager, Monticello Nuclear Site
G. Crosby, Superintendent, Quality Services
B. Day, General Superintendent, Engineering
S. Halbert, Site Safety Administrator
M. Hammer, General Superintendent, Maintenance
*W. Hill, Plant Manager
G. Hudson, Superintendent, Security
P. Johnson, Manager, Nuclear Projects
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 the licensee representatives attending the resident inspectors' exit meeting.

2. Plant Operations

The plant was in a 61 day refueling outage during the inspection period. The reactor was taken critical on May 29, 1991, and the generator was synchronized to the grid, ending the outage, on May 31.

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 that 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.

The observed facility operations were verified to be in accordance with the requirements established under Technical Specifications, the Code of Federal Regulations, and administrative procedures.

b. Outage Activities (71707)

The inspectors observed outage activities such as fuel movements, reactor reassembly, pre-operational testing, and portions of the plant's return to power. The inspectors also attended outage execution meetings to ascertain whether work was coordinated such that required systems remained operable and shutdown risk was minimized.

Prior to the start of the outage the plant manager decided that activities would be scheduled such that there would always be at least two sources of off-site power and one diesel generator available to power the safety buses. This effort to minimize shutdown risk went well beyond Technical Specification requirements. The decision was fortunate in that in two events discussed in this report, one off-site power source was lost. In both cases the electrical distribution system worked as designed and power remained available to the vital loads.

Conservative management of risk was consistently demonstrated in day-to-day outage schedule decisions. Operability issues were resolved before systems were required to be available based on plant conditions and safety systems beyond Technical Specification requirements were kept operable. In some cases the decision to maintain as many safety systems operable as possible resulted in reportable events for spurious actuations of systems that were not required by plant conditions. In one case near the end of the outage, the plant manager made the decision to delay reactor startup until both trains of the combustible gas control system were operable, even though Technical Specifications would have allowed startup without them.

c. 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 April 17, 1991, the licensee reported to the NRC via the ENS (Emergency Notification System) that the control room emergency filtration train (EFT) system had shifted to the high radiation mode due to the tripping and subsequent restoration of a temporary power supply to one of the radiation monitors in the system. That portion of the EFT system was designed to protect control room operators from post accident radiation releases. The 10 CFR 50.72 report was followed up within 30 days by LER 91-006.

As reported in the LER and confirmed by the inspectors' reviews, the event was caused by a combination of an inadequate review of the starting current of loads supplied by a temporary power supply to a vital division 1 electrical load center and an inadequate procedure for restoring power to the EFT system. However, the outage activities were planned in such a way that none of the loads on the temporary power supply and neither division of the EFT system were required by Technical Specifications. In addition, the shifting of the EFT to the high radiation mode was per design and should have been expected during power restoration. Thus the event had no safety significance. The inspectors reviewed the licensee's corrective actions for the event and found them to be adequate. The LER is closed in section 5.a of this report.

(2) On April 19, 1991, while performing electrical maintenance on bus #11, a technician contacted energized 4160 volt stabs in a breaker cubicle and caused the 2R station transformer to trip. Since the 2R transformer was supplying all AC power to the plant at the time, the trip caused a momentary loss of AC power. The operable vital bus transferred automatically to the 1AR reserve transformer, and the operable #12 emergency diesel generator automatically started but did not load because the 1AR transformer had restored power to its bus. The security and #13 (nonsafety-related) diesel generators also started and supplied power to their respective loads.

The senior resident inspector responded to the main control room and observed the immediate actions of the operating crew. The fire brigade and plant nurse responded to the 4160 volt switchgear room and provided first aid to the technician who was severely burned. The victim and two other technicians who had been standing nearby were evacuated to a local hospital and the burned individual was airlifted to a burn center. After ascertaining that the plant was stable and power was available for vital loads, the plant manager ordered a limited activation of the technical support center to plan a course of action to restore power to the rest of the plant.

The licensee reported the event to the NRC via the ENS due to the automatic start of the emergency diesel generator. Since the injured man was not contaminated and since power was available to vital loads, the plant manager determined that a Notification of Unusual Event was not necessary. The

classification of the event was determined to be appropriate by the inspectors and was discussed in Inspection Report 50-263/91010 by a regional emergency preparedness specialist. The use of the Technical Support Center to respond to the event was a significant help in reducing activity and confusion in the control room.

The licensee formed an accident investigation team which included an outside consultant to determine the cause of the event and recommend corrective actions. The licensee issued LER 91-007 as a written followup report on the event. The LER will remain open pending the inspectors' review of the accident investigation and corrective actions. A further discussion of the inspectors' review of this event is contained in section 3.b of this report.

(3) On April 22, 1991, the licensee informed the NRC via the ENS that it had discovered a degradation of the reactor coolant pressure boundary in that about 60% of the control rod drive housing flange cap screws inspected had indications of cracking just below the cap screw head. The licensee issued LER 91-008 as a written followup. This issue is further discussed in section 4.a of this report and also in Inspection Report 50-263/91006 by a regional inservice inspection specialist. The LER will remain open pending completion of corrective actions.

(4) On April 23, 1991, the licensee made a Notification of Unusual Event (NUE) when a contaminated injured man was transported by ambulance to the local hospital. The man had suffered a broken arm when a sandbag being brought into the torus for sand blasting operations fell on him. Shortly after arriving at the hospital, his protective clothing was removed and it was determined that he had no skin contamination at which time the NUE was terminated. A regional emergency preparedness specialist reviewed the licensee's actions with regard to this event as reported in Inspection Report 50-263/91010. This event is discussed further in section 3.b of this report.

(5) On April 24, 1991, the licensee informed the NRC via the ENS that it had discovered a potential degradation of the reactor coolant pressure boundary in that a painter had noted an 18 inch shallow linear indication in the torus shell. The licensee removed a sample of the indication for laboratory analysis and performed a weld repair. Analysis of the sample showed that the indication was a lap which had occurred during the original rolling of the plate and it showed no evidence of propagation. On May 17, 1991, the licensee withdrew its 10 CFR 50.72 notification because the indication was determined to be within the American Society of Mechanical Engineers standards. Thus no LER was issued. A regional inservice inspection specialist reviewed the licensee's decision and determined it to be acceptable as reported in Inspection Report 50-263/91006.

(6) On April 27, 1991, while replacing cables for environmental qualification maintenance, the licensee discovered that cables for secondary containment isolation damper VD-25 and VD-26 solenoids were routed in the same cable tray for approximately ten feet. Those solenoids were powered from separate electrical divisions and their wiring drawings indicated that electrical separation was required for the cables. The licensee reported the event to the NRC via the ENS and instituted walkdowns looking for additional separation problems. Separation was required for most safety-related electrical circuits to ensure that a single failure of a cable tray, conduit, or junction box would not prevent both redundant trains of a system from performing their design basis functions. This issue is discussed further in section 4.d of this report.

(7) On May 6, 1991, the licensee informed the NRC via the ENS that during a routine tape changeout on the chlorine detector on the control room emergency filtration train (EFT) system, it had discovered that the tape drive motor was inoperable on one detector. The chlorine detectors are designed to protect the control room operators from a toxic chlorine release on or near the site. The licensee initially reported that the inoperable drive motor rendered the EFT inoperable but later retracted the 10 CFR 50.72 call when further analysis demonstrated that the chlorine detector still would have performed its design function. Thus no LER will be issued for this event. The inspectors found the licensee's operability determination to be acceptable.

(8) On May 7, 1991, the licensee informed the NRC via the ENS that it had experienced a spurious trip of the reactor protection system. During core reloading intermediate range monitor channels 14, 16, and 18 experienced a high-high trip causing a reactor scram signal. The reactor was partially fueled with all control rods inserted at the time of the event, thus no rod motion occurred and the event had no safety significance. The cause of the scram was believed to be an electrical noise spike but the exact cause had not been determined at the end of the inspection period. The licensee intended to submit LER 91-010 as a written followup for the event. The inspectors will review the LER when issued.

(9) On May 13, 1991, the licensee informed the NRC via the ENS that a condition in the combustible gas control system (CGCS) had been discovered while shutdown that could have prevented its proper operation while the plant was at power. During a surveillance on the hydrogen recombiners, excessive setpoint drifts were discovered on one annunciator/trip card in the A train and two cards in the B train. The setpoints had changed such that both trains would have tripped off on high temperature in the reaction chamber before the chamber actually reached a high enough temperature for the recombination reaction to take place.

It was not known how long the conditions had existed although both trains had been tested satisfactorily in late March, 1991.

At the time of discovery, the recombiners were not required to be operable per Technical Specifications and had not been required since the reactor shutdown on March 31, 1991. Thus the trains could only have been inoperable when required for one or two weeks. The licensee had not determined the exact cause of the setpoint drift at the end of this inspection period. It intended to submit LER 91-011 as a written followup of the event. The inspectors will review the LER when issued.

(10) On May 24, 1991, the licensee informed the NRC via the ENS that it had experienced a spurious actuation of the control room emergency filtration train (EFT) system in the high radiation mode. At the time of the event the reactor was shut down and the EFT system was not required to be operable by Technical Specification. Thus the event was not considered safety significant. The actuation was caused by a spike on one of the EFT radiation monitors during a short AC power transient when the 2R station transformer tripped and power shifted to the 1R transformer. Such EFT actuations on AC power transients have been common at this plant and other similar actuations are discussed in sections 2.c.(1) and 5.a of this report.

The trip of the 2R transformer was unexpected and happened when a reactor feed pump was started. The 2R transformer supply had been modified during the outage and although the initial indications were that a ground fault had occurred, later investigation indicated that the fault may have been with the fusing and relaying circuits of the ground fault detector. The 2R transformer remained isolated during the reactor startup at the end of the refueling outage and investigation was continuing at the end of the inspection period. The licensee intended to issue LER 91-012 as a written followup for the event. The inspectors will review the LER when issued.

d. Engineered Safety Feature System Walkdown (71710)

The inspectors performed a detailed walkdown of the automatic depressurization system (ADS).

The design bases for the ADS were:

a. To provide a backup to the high pressure coolant injection system for depressurizing the reactor vessel in time to permit the low pressure coolant injection to prevent fuel clad melting;

b. Automatically actuate after receipt of simultaneous residual heat removal or core spray pump running and low-low reactor water level signals;

c. Delay automatic operation sufficiently to permit the reactor operator to evaluate the need for depressurization and forestall automatic operation if desired.

The inspectors reviewed drawings, assessed equipment conditions, inspected relay and breaker cabinets, verified instrumentation installation and calibration, reviewed operability testing, and verified that support systems essential for system performance were operational.

The inspectors verified that the lineup procedure matched the plant drawings and the as-built configuration. The majority of the system was located within the drywell and the torus. Walkdowns of these mechanical portions of the system were performed during the current refueling outage while the breakers and electrical instrumentation portions were reviewed during the observation of surveillance testing for the low-low set logic function. Instrumentation calibration records were reviewed and found to be current and indicated that the significant process parameters were being maintained at their proper values.

A detailed review of the portion of the ECCS Automatic Initiation Test 0113, ADS System Simulated Automatic Actuation; and 0452, ADS Inhibit Switch Test, was performed to assess the adequacy of the testing and the validity of the results obtained in previous testing. Specifically, the inspectors verified that the loss of preferred AC power bus transfer logic had been tested and verified as being operable. The ECCS Automatic Initiation Test that was performed during the previous refueling outage had several temporary changes made to it, and is being extensively revised for the present outage. The portion addressing the operability of the ADS appeared adequate.

This walkdown of the ADS did not reveal any shortcomings or deficiencies in the design or operation of the system although some editorial and typographic problems were noted with the operating manual and procedures for ADS.

No violations or deviations were identified.

3. 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.

a. During the refueling outage portions of numerous maintenance and surveillance activities were observed. All of the work observed was being conducted properly and in accordance with applicable procedures. Twice daily outage execution meetings were held to insure that work was efficiently coordinated and problems were expeditiously resolved. The inspectors also noted increased presence of power supply and plant QA personnel in the field as well as an increased emphasis on performance based assessments and worker practices in their reports.

b. During the refueling outage, three severe injuries requiring evacuation of personnel to hospitals occurred. Section 2.c.(3) of Inspection Report 50-263/91005 discussed the first event involving a broken leg. Sections 2.c.(2) and 2.c.(4) of this report discussed the other two events involving an electrical burn and a broken arm. The inspectors reviewed the circumstances surrounding the events as well as the licensee's accident investigation reports to ascertain whether they had involved common root causes.

None of the events involved permanent plant personnel. Two involved contractors and the other involved company employees from another sites. Although the final report from the investigation team investigating the electrical burn event was not available at the end of this inspection period, and the individual involved had not been interviewed due to the seriousness of his injuries, the cause was preliminarily attributed to personnel error on the part of the electrical technician. The licensee's investigation reports also attributed the primary causes of the other two injuries to personnel errors on the part of the victims.

The inspectors reviewed the licensee's accident investigation reports and discussed them with plant personnel including the plant manager and the site safety administrator. The inspectors reviewed time sheets for the workers involved. Overtime did not seem to be a factor in any of the events. All of the victims had worked a total number of hours within the NRC's guidelines for key maintenance personnel. Although individual personnel errors were involved in each of the events, both the inspectors and the licensee concluded that they could have all been avoided by first line supervision paying closer attention to work practices. In the case of the broken leg and broken arm, workers were moving heavy loads by hand instead of using proper rigging techniques. In the case of the burn, the worker was not wearing protective clothing suited for work on high voltage switchgear. For the burn incident, an investigation was also performed by OSHA. The final results of that investigation were not available at the end of this inspection although preliminary

information given to the site safety administrator indicated that inadequate first line supervision would be indicated as a significant contributing cause.

No violations or deviations were identified.

4. Engineering and Technical Support (71707)

a. As discussed in section 2.c.(3) of this report, the licensee discovered that a large percentage of the housing flange cap screws on the control rod drive (CRD) housings had indications of cracking. Each CRD housing was bolted to the flange on the reactor vessel by eight cap screws. The licensee was performing inspections of the cap screws as part of the routine refurbishment process for eight CRDs during the refueling outage.

The licensee had been made aware of cracking indications at other plants by General Electric Service Information Letter (SIL) No. 483 of March 27, 1989. The SIL recommended that licensees perform visual inspections of all cap screws during routine CRD maintenance. The licensee went beyond the recommendation and performed magnetic particle testing on the screws. When 37 out of 72 screws inspected were found to have indications, the licensee elected to replace four screws on each of the 121 CRDs with new screws. At the NRC's request, the licensee provided a number of the screws with indications of cracking as well as a sampling of the new screws for laboratory testing. The final report of the testing was not available at the end of this inspection period but preliminary information was that the cracks were only shallow and that the chance of CRD housing failure was extremely small. In addition, the failure of a CRD housing would be mitigated by the control rod drive support structure and has been evaluated in the Updated Safety Analysis Report.

The inspectors attended various meetings and discussions among licensee personnel during the evaluation of the cap screw problem. The licensee's response to the SIL, evaluation of the problem, and technical solution was considered excellent and demonstrated a conservative approach to reactor safety.

b. The licensee intended to install new feedwater flow venturi nozzles during the refueling outage to help resolve questions concerning the accuracy of previous feedwater flow measurements. This issue was previously discussed in Inspection Report 50-263/90016 and was being tracked as Unresolved Item 263/90016-02. The new nozzles were not available from the vendor in time for installation during the refueling outage so the licensee installed pipe spool pieces in their place. The majority of the electrical installation, instrumentation tubing, and other work associated with the modification was done so that the nozzles could be installed during a future short outage when they became available.

As discussed in Inspection Report 90016, the licensee performed chemical and radioactive isotope tracer tests in 1990 because they

suspected that feedwater flow was lower than indicated by installed instrumentation. However, the tests indicated that feedwater flow was higher than indicated. This raised the possibility that the core was being operated at higher than licensed thermal power and was operating closer to thermal limits than analyzed. The inspectors and regional staff reviewed Safety Review Item No. 90-026 which provided the licensee's analysis demonstrating that core thermal limits would not be violated even if the tracer tests were accurate. However, because of other heat balance data and certain problems discovered later with the tracer tests, the licensee still believed that they were actually operating at lower than indicated feedwater flow. This item will remain unresolved pending the installation and analysis of data from the new feedwater flow nozzles.

c. During the refueling outage the licensee replaced the reactor mode switch with a new model, developed by the BWR owners group, with an improved design. The new switch was designed to correct a problem with the old switch in which it often went slightly past the desired position when being rotated resulting in several reactor trips and other reportable events. During an evaluation of the new switch in preparation for testing it, the licensee determined that the logic of the new switch was slightly different than the old one. With the new switch, the low steamline pressure isolation function remained bypassed until the switch fully reached the "run" position. Also, the intermediate range monitor high-high trip became bypassed as soon as the switch left the "startup" position. Should the switch become "hung up" between the "startup" and "run" positions, and the operators not notice it, it would have been possible to raise reactor power above 25%. Then, if the plant would suffer a pressure regulator failure or other event that caused reactor pressure to drop below 800 psig, a safety limit would be exceeded with no automatic action.

Testing by the licensee demonstrated that it was possible for the switch to stop between positions but that it took a deliberate effort to make it stop and it was quite easy to feel when the switch actually reached the new position. The inspectors were also given the opportunity to exercise the switch to evaluate the possibility of it stopping between positions. Although both the licensee and the inspectors believed that it was unlikely but possible for the switch to stop between the "startup" and "run" positions, the licensee designed two modifications to minimize the chance of such an event from happening undetected. It installed a new main control board annunciator which would be lit whenever the low steamline pressure isolation function was bypassed. Thus the operators would be able to tell when the switch actually reached the "run" position because the annunciator would clear. The licensee also intended to install a computer alarm that would monitor the switch contacts and alarm whenever the switch was between positions for more than about five seconds. The second modification had not been installed at the end of the inspection period.

The inspectors regarded the licensee's independent discovery and innovative resolution of the logic problem with the new mode switch to be an example of excellent work by the engineering staff.

d. As discussed in section 2.c.(6) of this report, the engineering staff was tasked with performing walkdowns of secondary containment systems to look for cable separation problems. When an additional separation problem was found with cables for solenoids for secondary containment dampers VD-9 and VD-10 being routed through the same junction box, the licensee expanded the scope of its walkdowns to include all secondary containment dampers, the standby gas treatment (SBGT) system, and primary containment isolation valves.

The licensee discovered three separation problems in the SBGT system. Power and control cables for both trains of room heaters were routed in the same conduit, low flow alarm cables for both off-gas stack dilution fans ran in the same conduit, and limit switch cables for damper AO-2982 ran in the same conduit. In all of the above cases, mandatory electrical separation was indicated by notes on the electrical drawings. Eleven containment isolation inboard and outboard valves in the nitrogen inerting, oxygen sampling, and post accident sampling systems were also identified to have electrical cables to operating solenoids that were not separated. For those valves, mandatory separation was not indicated on the installation drawings although it was indicated for all other containment isolation valves. In addition, the General Electric specification and elementary drawings for the valves did indicate that separation was required. All of the above systems were considered to be parts of engineered safeguards systems.

The Monticello Updated Safety Analysis Report (USAR) stated in section 8.8, "Cables and Raceways," "The specific cables and raceways in the category for which separation is provided include those for all circuits involved in the control, protection, and supply of power to the reactor protection and engineered safeguards systems. Circuits related to these systems, but for which separation is not necessarily provided, include cables and raceways for instrumentation and alarms which have information significance only, and which do not involve automatic control functions of any kind. Furthermore, separation is not necessarily provided for power circuits where the particular system is such as to be fail-safe for loss of power."

The licensee performed modifications to provide electrical separation for the secondary containment damper pairs discussed above. In the case of the SBGT room heaters, the licensee's safety evaluation justified leaving the cables as they were because each heater was protected by individual fuses and the heaters were not required during SBGT system operation. For the off-gas dilution fan low flow alarms, the licensee disconnected the alarm from one of the fans and intended to run the other fan until a modification could be made. For damper AO-2982, the licensee disconnected the limit switches and isolated the damper in the closed position until a permanent modification could be made. The damper was required to be

closed when SBGT operated in the accident mode. For the nine primary containment isolation valves, the licensee determined that the valves all failed closed upon loss of power. Since that was their required accident position, the licensee decided to leave the valves as they were and evaluate whether a permanent modification was desirable.

The licensee discussed the findings and intended actions with the NRC in conference calls on May 13 and 14. In those calls, the plant manager verbally committed to complete walkdowns of those portions of the reactor protection system and emergency core cooling systems that were not previously inspected for separation. In those walkdowns it was discovered that signal cables for source range monitors A and B go through a common junction box and cables for source range monitors C and D go through another common junction box. Also position indicating switch cables for both trains on residual heat removal system isolation logic from inboard shutdown cooling suction valve MO-2029 ran in a common cable tray. Mandatory cable separation was indicated on the installation drawings for these additional cases.

On May 28, 1991, the licensee issued LER 91-009 detailing the findings and corrective actions for the separation issues in the secondary containment and standby gas treatment systems. In the LER it committed to issuing a revision to discuss the additional findings in the primary containment isolation, reactor protection and emergency core cooling systems. Another conference call was held between the licensee and the regional staff on May 28. In that call the licensee discussed actions it had taken to date and future actions planned to resolve the issues. It also presented the results of the reviews which indicated the none of the remaining issues would prevent any system from performing its safety function for design basis accidents and would not hold up plant startup. The NRC voiced no objections to plant startup.

The licensee was conducting a search for construction records which would show whether the deviations between the field installation and the installation drawings and specifications had been properly evaluated at the time of construction. The issue of cable separation is considered an Unresolved Item (263/91007-01) and will be assigned to the Division of Reactor Safety for resolution. The LER remains open pending issuance of the supplement and completion of the corrective actions.

e. The licensee intended to install support brackets on the jet pump risers inside the reactor vessel to resolve a problem discovered during the last refueling outage with cracking of one of the riser braces. Because the vendor could not supply the brackets in time to support the outage, that work was deferred. The licensee conducted a detailed inspection of the jet pump braces with an underwater camera focusing especially on the one previously discovered cracked. It discovered that the existing crack had not expanded during the last operating cycle and no new cracks were discovered. The inspectors reviewed photographs of the crack and compared them to photos from the previous outage.

During the last operating cycle the licensee limited the recirculation pump speed to less than 92% of maximum in order to prevent harmonic vibration and fatigue cracking of the braces. This practice appeared to be effective and the licensee intended to continue it during the next cycle. This issue was previously discussed in Inspection Reports 50-263/89020, 89023, and 90022. The licensee issued LER 89-021 and 89-021 supplement 1 discussing this issue. The LER will remain open pending final resolution.

One unresolved item was identified.

5. Safety Assessment/Quality Verification

a. Licensee Event Report (LER) Follow-up (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:

(Closed) LER 90-003: Procedure Inadequacy Causes Unplanned Emergency Filter Train Actuation.

(Closed) LER 91-001: Loss of Power to Radiation Monitor Resulting in Unplanned Emergency Filtration Treatment System Actuation to High Radiation Mode.

(Closed) LER 91-007: Inadequate Procedures When Restoring Power to Emergency Filtration Train Result in Unplanned Transfer to High Radiation Mode.

All of the above events involved actuations of the emergency filtration trains to the high radiation modes following loss of power to the radiation monitors. One of the problems was that most personnel were not aware that restoring power to one of the radiation monitors would cause the opposite train to shift modes. That fact has been incorporated into procedures as a planned actuation when restoring power and thus was no longer reportable in accordance with 10 CFR 50.72 and 50.73. The other problem was that a spurious loss of power to either of the radiation monitors would cause its respective train to shift to the high radiation mode. This was a design feature of the system and, although it caused reportable engineered safety feature actuations, was not considered safety significant.

The inspectors noted that LER 91-006 did not list any previous similar events. However, LER 90-003 should have been listed as a similar event. It involved almost exactly the same sequence of events and same root cause.

Corrective actions for LER 90-003 included revising the modification procedure being used to reflect that the opposite train would shift to the high radiation mode when power was restored to the radiation monitor but did not include correcting the normal system operating procedures to identify the same fact. Had the corrective actions in LER 90-003 been more complete, LER 91-006 may have been avoided. The inspectors discussed this finding with the author of LER 91-006. These items are considered closed.

(Closed) LER 91-002, LER 91-002 Supplement 1, and Open Item 263/90026-01: Control Power Circuit Breaker for Filtration Unit Heater Found Open Resulting in Inoperability of Control Room Emergency Filtration System.

This issue involved a control power circuit breaker for the "A" emergency filtration train filter heater. As reported by the licensee in supplement 1 to the LER, no cause for the circuit breaker could definitely be determined. However, analysis demonstrated that the loss of the heater would have only a minor effect on system operation and that 10 CFR 50, Appendix A, General Design Criterion 19 limits for control room operator dose would not be exceeded. The licensee has locked all 120 volt AC distribution panels which should help prevent anyone from inadvertently opening an incorrect circuit breaker. This issue is considered closed.

b. Evaluation of Licensee Self-Assessment Program (40500)

The inspectors reviewed several licensee safety review item reports and attended Operations Committee meetings to ensure that safety questions were being adequately evaluated and resolved. Among the safety issues reviewed during the inspection period were the adequacy of control rod drive housing cap screws, electrical cable separation issues, feedwater flow questions, the jet pump riser brace crack, and reactor mode switch logic problems. Each of these issues is discussed separately in this report. The inspectors found that the licensee's safety assessment of the issues was thorough, management attention at the plant manager and general superintendent level was focused on the problems, reports were clear, and resolutions were conservative.

c. Follow-up of Regional Requests (71707)

(1) In response to a request for information from the regional staff, the inspectors examined the Technical Specifications and Updated Safety Analysis Report and talked to the system engineer to gather information about the seismic qualification of the diesel generator fuel oil supply system. The inspectors reported that the diesel generator day tanks, with at least an eight hour fuel supply for each diesel, were seismically qualified. In addition, the pump house and transfer pump from the main underground fuel oil tank was qualified based on a

recent analysis reported by the licensee in LER 90-019. The underground tank, with at least a seven day supply for one diesel generator, and the underground piping were not specifically qualified. At the time the plant was licensed, seismic qualification of the entire fuel oil system was not required.

(2) In response to a request by the regional staff, the inspectors reported on the incorporation of the shift technical advisor (STA) into the operating crew. At Monticello, the shift manager, who is the senior member of each crew, also functions as the STA. The plant recently completed a program whereby all the shift managers obtained engineering degrees. The shift manager is an integral part of the crew, taking part in the shift turnover, and spends a significant amount of his time in the control room.

(3) In response to a request by the regional staff, the inspectors examined valves with reach-rod systems for manual operation to determine if any such valves were required to be manually operated as part of any accident analysis or emergency operating procedures. If so, the inspectors were to determine if the licensee had a program to insure that the reach-rod systems remained operable. After discussions with several licensed operators and walkdowns of the plant, the inspectors determined that there were no reach-rod operated valves at Monticello that would be required to be operated in an emergency.

(4) In response to a request by the regional staff, the inspectors examined the various systems the licensee used to track NRC and other regulatory commitments. The inspectors reviewed various administrative control procedures and held discussions with plant personnel to gather the information. The inspectors determined that the licensee uses tracking systems such as the Operations Experience Tracking System, NRC Response Reminders, Assigned Items, Power Supply QA Findings and Deficiencies, and Plant QA Findings and Deficiencies.

No violations or deviations were identified.

6. 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 is discussed in section 4.d.

7. Exit Interview

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on May 31, 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.