U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Number 50-263/90018(DRS)

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, Minnesota

Inspection Conducted: October 1 through November 2, 1990

Inspection Team:
R. A. Westberg, Team Leader
S. V. Athavale, Assistant Team Leader, NRR
F. H. Burrows, Electrical Engineer, NRR
Z. Falevits, Reactor Inspector RIII
D. S. Butler, Reactor Inspector RIII
W. A. Slover, Reactor Inspector RIII

NRC Consultants:
O. S. Mazzoni, AECL (Atomic Energy of Canada Ltd.)
L. Lazic, AECL
P. Pattantyus, AECL

Approved by: Rolf A. Westberg
Rolf A. Westberg, Team Leader
Plant Systems Section
12/7/90
Date

Approved by: Ronald N Gardner
Ronald N. Gardner, Chief
Plant Systems Section
12/7/90
Date

Inspection Summary:

Inspection on October 1 through November 2, 1990 (Report No.50-263/90018(DRS))
Areas Inspected: Special electrical distribution system functional inspection (25107).
Results: The team determined that the electrical distribution system was generally acceptable. One open item was identified relative to the temperature in the battery room (Paragraph 2.3.4). Three unresolved items were identified relative to the as-built condition of the electrical systems (Paragraph 3.3.c), the lack of set point methodology for the degraded grid voltage setpoint (Paragraph 4.1.1), and the testing of the slow bus transfer (Paragraph 4.1.3). One violation was identified relative to the failure to assure that testing was evaluated for plant instrumentation left exceeding calibration tolerances (Paragraph 4.1.5).

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EXECUTIVE SUMMARY

From October 1 through November 2, 1990, a Region III team conducted an electrical distribution system functional inspection at Monticello Nuclear Generating Station to review the design and implementation of the plant electrical distribution system (EDS) and the adequacy of the engineering and technical support (E&TS) organizations. The team reviewed the electrical and mechanical support systems of the EDS, examined installed EDS equipment, reviewed EDS testing and procedures, and interviewed selected corporate and site personnel.

The team considered the design and implementation of the EDS at Monticello to be generally acceptable. For the most part, design attributes of the EDS were retrievable and verifiable although the team considered the condition of the relaying design documentation a weakness. Engineering calculations were technically sound although the team identified some nonconservative assumptions. The team considered the scope and implementation of the site program for surveillance testing of EDS equipment a strength. Control of modifications to the EDS was effective and there appeared to be an adequate interface between Engineering and Operations. The team found the EDS and related support equipment properly installed in the plant but had a concern that the as-built condition of the plant appeared to be different than the design drawings (Paragraph 3.4.c). The team considered the material condition of the EDS and housekeeping in the plant a strength. In addition, the team considered E&TS acceptable and the knowledge and expertise of the engineering staff a strength. The team considered the lack of a transient voltage analysis for the diesel generators a design weakness. Additionally, the team considered the program for preventive maintenance on the EDS fragmented and a weakness although the maintenance program was generally good as exemplified by the low rework ratio and low maintenance backlog.

The team also had several concerns that required further action. For example, the lack of set point methodology for determining the set point for the degraded grid voltage relays, the lack of testing of the slow bus transfer to demonstrate its functionality, the document deficiencies found in the as-built condition of the EDS, and the control of the temperature in the Division II battery room during the high radiation and toxic chemical emergency modes. These unresolved/open items require further review by the licensee and will be revisited during a subsequent inspection.

One team concern resulted in a violation of NRC requirements for the failure to perform an engineering evaluation for instruments left exceeding their as-left calibration tolerances.

1.0 Introduction

During electrical inspections at various operating plants in the country, the NRC staff identified various significant EDS deficiencies. Examples of these deficiencies included unmonitored and uncontrolled load growth on safety buses and inadequate modifications, design calculations, testing, and qualification of commercial-grade equipment used in safety related applications. The NRC considered weak E&TS to be one cause of these deficiencies.

The objectives of this inspection were to assess the performance capability of the Monticello EDS and the capability and performance of the licensee's E&TS in this area. For this inspection, the EDS included all the emergency sources of power to systems required to remain functional during and following the design basis events. EDS components reviewed included the emergency diesel generators (EDGs), 125Vdc Class 1E batteries, offsite circuits and switchyard, 4KV switchgear, 480Vac load centers (LCs), 480Vac and 120Vac Motor Control Centers (MCCs), 125Vdc MCCs, battery chargers, inverters, associated buses, breakers, relays, and other miscellaneous components.

The team reviewed the adequacy of the emergency, offsite and onsite power sources for EDS equipment, the regulation of power to essential loads, protection for postulated fault currents, and coordination of the current interrupting capability of protective devices. The team also reviewed the mechanical systems that interface with the EDS, including air start, lube oil, and cooling systems for the EDGs, plus the cooling and heating systems for the EDS equipment. The team walked-down originally installed and as-modified EDS equipment for configuration and equipment ratings and reviewed qualification, testing, and calibration records. The team assessed the capability of the licensee's E&TS organization with respect to personnel qualification and staffing, timely and adequate root-cause analyses for failures and recurring problems, and engineering involvement in design and operations. The team also reviewed training for Operations and E&TS personnel relative to the EDS.

The team verified conformance with General Design Criteria (GDC) 17 and 18 and the applicable 10 CFR 50, Appendix B criteria. The team also reviewed plant technical specifications (TS), the updated safety analysis report (USAR), and appropriate safety evaluation reports (SERs) to verify that TS requirements and licensee commitments were met.

The areas reviewed and the concerns that were identified are described in sections 2, 3, 4, and 5 of this report. Conclusions are given after each of these sections. A list of the personnel contacted and those who attended the exit meeting on November 2, 1990 is provided in Appendix A of the report.

2.0 Electrical Systems

2.1 Class 1E AC Systems

In order to assess the capability of the electrical system, the team reviewed the regulation of EDS loads, the overcurrent protection, and the coordination of protective devices for compliance with regulations, design engineering standards, and accepted engineering practices. The review included system descriptions, station USAR, equipment sizing calculations, system protection, controls and interlocks, equipment specifications, modification packages, licensee event reports (LERs), related test and operating procedures, one-line diagrams, elementary diagrams, and equipment layout drawings.

The characteristics of the power system electrical grid to which the Monticello plant is connected were reviewed to assess the adequacy of important parameters, such as voltage regulation, short circuit contribution, protective relaying, surge protection, control circuits, stability, and reliability. The preferred power supply transformers were reviewed in terms of their KVA capability, their connections to the safety buses, field installation capability, protection, and voltage regulation. The EDGs were reviewed to assess the adequacy of the KW rating, the ability to start and accelerate under assigned safety loads in the required time sequence, the voltage and frequency regulation under transient and steady state conditions, compliance with single failure criteria, and the applicable separation requirements. The 4KV safety buses and their connected loads were reviewed to assess load current and short circuit current capabilities, voltage regulation, protection, adequacy of cable connections between loads and buses, compliance with single failure criteria, adequacy of the fast bus transfer scheme in terms of any effects on the safety systems, and applicable separation requirements. The 480Vac safety buses and their connected loads were reviewed to assess load current and short circuit current capabilities, voltage regulation, protection, adequacy of cable connections between loads and buses, compliance with single failure criteria, and applicable separation requirements.

2.1.1 Transformer Protective Relaying

In inspecting the relay setting coordination curves, the team found that the coordination diagrams were missing many important features required to ascertain the adequacy of the settings. Examples of missing information included the transformer capability curves, the transformer full load and emergency ratings, the maximum inrush current, the connected cable/bus capability and the references to related source documentation. Due to the missing information, it was not possible to correlate the protective device curves against a manufacturer data sheet. The team considered this a weakness relative to design documentation.

2.1.2 Surge Protection

From the team's review of the protective relaying schemes and the protective settings for the Class 1E 4KV switchgear, the team questioned the capability of the ground fault detection system to detect phase to ground faults using the neutral grounding system. The team reviewed the setting and accuracy of the ground sensors and found that they were set at two amps, with an accuracy of two amps, which would give a potential pick up trip of four amps. The team was concerned that the system would be insensitive to ground faults involving higher fault impedances, as well as those occurring inside windings of machines. To verify the operation of the system for these cases, the team performed its own calculations to reevaluate the maximum ground fault current. The team found that the ground fault current would be higher than the five amps stated by the licensee, due to the presence of capacitive current components, thereby improving the system's fault detection capabilities. However, relative to damage at the point of the fault, the team was concerned that no calculations existed to determine the threshold time for significant damage. The team considered this aspect important in a system that provides only an alarm upon fault detection and where the equipment could remain energized for a considerable period of time under faulted conditions. Further, the fault would only be cleared after the equipment was taken out of service and the fault location identified. The licensee indicated that an evaluation of the damage time threshold would be performed.

2.1.3 1R Transformer 4KV Fault Calculations

The 4KV fault calculation applicable to the 1R transformer contained the following nonconservative assumptions:

a. The highest voltage source was assumed to be 1.05 per unit (PU). Based on Attachment II to the Bechtel calculations, the team calculated that the maximum PU voltage would be 1.078. The higher PU value would produce a proportionally higher fault value than included in the calculations.

b. The postulated location of the fault in the distribution system was assumed to be at the load side of the breaker feeding LC No. 109. Using the reactance values provided in the calculation, the team found that this assumed fault location did not provide for the worst possible short circuit conditions. Instead, the team concluded that the worst possible fault location was for a fault in the control rod drive (CRD) pump breaker located in switchgear No. 15.

Using the above information, the team calculated that the corrected fault value was 32,615 amps. The breaker interrupting rating was 30,782 amps which resulted in 3.17% overstressing. The licensee's response to the team's concern was that they were in the process of incorporating the short circuit analysis into their computerized computations, which should allow for a more accurate determination of the short circuit levels. The team found this acceptable based on the low probability of a fault of this magnitude, provided that the new calculations proceed expeditiously and show that the short circuit capabilities of affected equipment are not exceeded.

2.1.4 2R Transformer 4KV Fault Calculations

The 4KV fault calculation applicable to the 2R transformer contained the following nonconservative assumptions:

a. The fault values were calculated at the terminals of the load equipment, rather than at the load terminals of the critical breakers. Therefore, the short circuit values calculated did not reflect the values required for breaker sizing. The team noted that even with these nonconservative assumptions the breaker interrupting ratings were exceeded.

b. The value of voltages used in the calculations did not account for metering errors in the field surveying instruments and potential voltage levels at the switchyard higher than 1.0 PU were not considered.

The licensee's response to the team's concern was the same as for Section 2.1.3. The team found it acceptable based on the fact that the licensee had previously identified the problem with high fault current on this device. The 2R transformer had been taken out of service by the licensee in 1988.

2.1.5 Transfer of 4KV ESF Buses Between Offsite Sources

The team was concerned that contrary to the description in the USAR, there was no fast transfer from primary station transformer 2R to auxiliary reserve transformer 1R. This was due to the fact that 2R was taken out of service in 1988. While transformer 2R could be available for plant shut down, its use is restricted to emergency conditions, and cannot be relied on as an available offsite source. The team considered this reduction in the number of available offsite sources and the associated elimination of the fast transfer scheme to be a degradation of the overall reliability and availability of the offsite sources. However, the team considered it acceptable since the current transformer line-up is described as an alternative in the USAR. (See Section 4.1.3 of this report for a discussion of the team's concern with testing of the slow transfer.)

2.1.6 EDG Protective Relaying

The team questioned the ability of the EDG protective relaying to prevent overloading the EDG in the event it was tied to the grid and the grid voltage collapsed. In response to the team's concern, the licensee performed an analysis which demonstrated that the voltage overcurrent protection would trip the EDG output breaker under the postulated conditions. However, the analysis performed by the licensee failed to include the damage curve of the generator, which precluded the licensee from determining that the generator would not be damaged. As a result of the finding, the licensee committed to review the relaying protection studies to include the generator protective limits. The team considered this issue to have low safety significance since the probability of the postulated conditions was considered low.

2.1.7 Relay Coordination

The team found that the EDG output overcurrent relay did not coordinate with the downstream LC feeder breaker overcurrent relay for a single-phase-to-ground, or a phase-to-phase fault at the low voltage side of the LC transformer. Utilizing the information provided by the licensee on October 31, 1990, the team calculated that the fault might not be cleared by the LC protective relay but would be cleared by the EDG overcurrent relay. This would trip the output breaker and shut down a complete division. The fault clearing time resulting from the operation of the generator overcurrent relay was estimated to be in the order of thousands of seconds, which could result in serious damage to the LC transformer. The likelihood of either a phase-to-ground or a phase-to-phase fault is considered relatively higher than a three phase fault, since most faults start from phase to ground insulation failures.

Under a phase-to-ground fault condition, if there is no tripping, there would be 1.73 higher than normal phase to ground voltages on the unaffected phases. This higher than normal voltage could induce a second phase-to-ground fault in one of the unaffected phases, such that a phase-to-phase fault could ensue. The licensee committed to reviewing and revising the relaying protective studies as necessary. The team considered the safety significance to be minimal since there was another full size EDG. However, this was considered to be a weakness relative to design.

2.1.8 Transient Voltage Regulation

The team found that there was no transient analysis to model EDG voltage regulation under transient conditions. The EDGs are required to accelerate under load to full speed while maintaining acceptable voltage at the bus. Adequate demonstration of this requirement can only be provided by a combination of analysis and testing; however, the only documentation available for verifying compliance with the requirement of adequate voltage regulation was a strip recorder chart from an Emergency Core Cooling System (ECCS) test. The strip chart had not been analyzed for accuracy of related instrumentation. Furthermore, the preloading conditions during an actual event (i.e., the loading existing prior to starting the last large load) cannot be properly simulated during a test. The test cannot simulate the preloading conditions because the running pumps cannot be fully loaded, and random loads, such as thermostatically controlled HVAC cannot be simulated. As a result, the values indicated in the recording are non-conservative relative to the actual values that could be expected during an accident. The team concluded that this was a weakness relative to design documentation.

2.1.9 Switchgear Short Circuit Ratings

The team found that the 480Vac fault calculation, performed by Bechtel, contained the following nonconservative assumptions:

a. The highest source voltage for switchgear No. 15 was assumed to be 1.00 PU, while the NSP voltage field survey determined the maximum value to be 1.04 PU. In addition, NSP calculation No. DP-15-01 determined this maximum value to be 489Vac, or 1.02 PU, with a 115KV switchyard value of 117.5 versus a maximum of 124KV. Using the higher source voltages, the team calculated the fault values to be approximately 7.5% higher than the Bechtel calculation. This resulted in a short circuit current of 22,887 amps which exceeds the 22,000 amps capability of the equipment.

b. The fault calculation was carried out for LC No. 104, but no justification was given for the selection of this LC as the worst case. The team found that LC No. 103 had 19% higher loading than the selected LC.

The licensee's response to the team's concern was that the licensee is in the process of incorporating the short circuit analysis into their computerized computations, which should allow for a more accurate determination of the short circuit levels. The team found this acceptable, provided that the new calculations proceed expeditiously and show that the short circuit capabilities of affected equipment are not exceeded.

2.1.10 Motor Control Centers

The team found that the maximum control cable length calculation performed by Bechtel included the following unsubstantiated/nonconservative assumptions:

a. The inrush current was calculated to be 1.17 amps based on 96Vac (80% of 120V) available at the contactor terminals. However, the 80% pick up voltage was not substantiated by relevant back up documentation.

b. The voltage level at the MCC bus was assumed to be 90% of nominal. Contrary to this assumption, the new calculations performed by NSP indicate an acceptable voltage level of 88.75% or 426Vac.

In response to the team's concerns, the licensee was able to obtain confirmation from the manufacturer that the assumed pickup voltage was correct. The licensee indicated that the voltage assumption will be changed to be consistent with the latest plant voltage studies. The team found this acceptable.

2.1.11 Conclusions

The team determined that, in general, the performance of the Class 1E AC system was acceptable. Design attributes of the EDS were generally retrievable and verifiable, although the adequacy of the relaying design documentation was considered to be a weakness. Engineering calculations were found to be technically sound although some non-conservative assumptions were identified. The lack of a transient voltage analysis for the EDGs was considered to be a weakness.

2.2 DC Systems

The team reviewed the station Class 1E DC systems, 120Vac inverters and electrical containment penetrations for design compliance to applicable standards and codes. The inspection included a review of the ±24Vdc, 125Vdc and 250Vdc battery designs with respect to sizing, duty cycle loading, electrolyte temperature, battery age and capacity. The associated charger designs were reviewed for total loading requirements and the bases of these calculations were checked for their adequacy. The inverters' sizing and design criteria were reviewed for their ability to meet applicable standards and power input/output requirements. Fault study calculations for the ±24 Vdc, 125Vdc and 250Vdc batteries were reviewed relative to system parameters and requirements, applicable standards, correctness, accuracy and standard engineering practices. Voltage drop studies and cable sizing calculations for the ±24Vdc, 125Vdc, 250Vdc and 120Vac systems were reviewed relative to system parameters and requirements, applicable standards, correctness, accuracy and standard engineering practices. A review of breaker/fuse coordination and sizing was performed to determine if protection schemes for the DC systems conformed to standards and practices used for station design. The team also reviewed the electrical penetration design against standards applicable during station design and construction.

2.2.1 250Vdc Battery Sizing

Division I & II 250Vdc batteries were not sized to include full capacity output of the 120Vac inverters. For example, the Division II calculation assumptions ignored the full load capacity of the inverters and sized the battery capacity on existing inverter loads of approximately 97.65 amps during Station Blackout (SBO). Because the full load current limit output of the inverters (approximately 208.2 amps) was not considered, if a fault in the inverter occurred, the battery capacity on both divisions could be rapidly reduced with no warning. The Inverter loads are not expected to current limit if AC power is lost because this would require a second failure. Therefore, this concern is not valid when considering a single failure. However, this was considered to be a design weakness as most valid designs normally consider the potential failure of internal components.

2.2.2 250Vdc Load Profile

There were two conflicting load profiles for the 250Vdc system. Bechtel calculation No. 802-012-E-1 (1987) for the 250Vdc Division I battery contains a SBO load profile that peaks at 653.4 amps at minute 20 for one minute. Other significant loads vary between 118.4 amps and 198.4 amps. However, the 1990 Impell battery capacity calculation uses a different load profile that peaks at 279.26 amps at minute 59 for one minute. The load alternates between 107.66 amps and 152.66 amps for other periods with a random load of 52.31 amps.

All new calculations performed during the EDSFI used the Impell load profile as a basis. The licensee committed to declare the Bechtel load profile void in its documentation. The team considered this acceptable.

2.2.3 250Vdc Battery Main Fuse Coordination

It was not evident from the time-current characteristics (coordination curves) associated with the 250Vdc Division I battery 800 amp fuse that feeds Panel D 31 if the fuse would adequately protect the battery. The maximum short circuit current supplied by the batteries is 9,183 amps. Calculation No. 802-012-E-1 credited the main fuse with backup protection in the event of a breaker failure and a fault on the D 31 bus. An investigation by the licensee produced battery vendor information that showed the available station battery short circuit current would blow the fuse approximately one second after a hard fault on panel bus D 31. Information contained in the battery manufacturer's recommendation No. E 0910-178-009 indicated the installed fuse that protects the battery should nominally blow 20 msec after a fault. A recommended range was 10 msec. to 100 msec. Therefore, this fuse would take 8 to 10 times longer to blow than recommended by the battery manufacturer. The manufacturer stated that this could result in "disastrous consequences for the battery and its surrounding environment." The team considered this a design weakness because the fuse should be designed to protect against the consequences of a fault. However, the team determined that since there was another division of power and the fuse was a back-up for the safety related breaker, reactor safety was not compromised.

2.2.4 250Vdc System Short Circuit Study Temperature Ratings

The temperature rating that defines the parameter attributes for the 250Vdc short circuit calculations was not consistently applied. For example, the ambient temperature was rated between 25°C and 40°C. The temperature specifications for the batteries specified a range of 70°F (21°C) to 88°F (31°C) ambient with a normal temperature of 77°F (25°C). The cable resistance contribution to the short circuit was calculated at a conductor temperature of 75°C. The insulation referenced in the calculation was either XLPE or EPR, which are both 90°C rated insulations. No mention of the battery electrolyte temperature was made. New calculations were submitted during the inspection that employed the most conservative ratings for all temperatures. The team found these new calculations acceptable.

2.2.5 125Vdc Voltage Drop Calculations

No justification was given within the assumptions section or the design input section of 125Vdc voltage drop calculation No. 0910-178-002 to show why the minimum acceptable voltage for the inverters and EDG field flash circuits was 105Vdc. Lower than acceptable voltage may be seen at the device terminals (see next section). The licensee committed to change the assumptions in the referenced voltage drop calculation to indicate that the operating range for the inverters is 100 - 140Vdc. In both instances the reference document will be included in the assumption; therefore, the team considered this response to be acceptable.

2.2.6 125Vdc Minimum Voltage

The team was concerned that the voltage drop across the EDG field flash cables was not properly factored into calculation No. 0910-178-002. In Table 8.1, the minimum acceptable voltage at the EDG field flash terminals was 105Vdc which was identical with USAR Section 8.5.2.1 that indicated the battery output voltage does not drop below 105Vdc. The licensee committed to modify the calculation by initiating Safety Review Item (SRI) 90-033 to change Section 8.5.2.1 to state that the Division I battery will not drop below 108Vdc and the Division II battery will not drop below 109Vdc. Low voltage alarms would be recalibrated to match the new conditions. The team was satisfied that this would alleviate the problem.

2.2.7 120Vac Inverter

The team was concerned that the inverter design did not consider the voltage drop across battery to inverter cables, because the requirements for the Class 1E instrument power supply indicated that the input voltage for the inverters should be in the range of 210 - 280Vdc and the USAR specified that the minimum voltage for the 250Vdc system was 210Vdc. This meant that when the minimum battery voltage of 210Vdc was reached, the input voltage to the inverter would be reduced below the minimum input voltage requirement by the amount of voltage drop in the connecting cable. The licensee initiated SRI 90-033 to change USAR Section No. 8.5.I.1 to read that the Division I battery will not drop below 218Vdc and the Division II battery will not drop below 216Vdc. Low voltage alarms would be recalibrated to match the new conditions. This alarm will result in operator actions to prevent battery output voltage from dropping below the minimum required inverter voltage. The team considered these actions acceptable since this was part of the original design and the operators check the inverters on each shift.

2.2.8 MCC D 313 Coordination

The team's review of Calculation No. 802-012-E-1 indicated that a fault at the load side of a 100 amp fuse on MCC D 313, fed from Panel D 31, would also trip the MCC D 131 supply breaker (225 amp), thus cutting power to this and other loads supplied from MCC D 313. SRI No. 87-027 justified this lack of coordination, because it would require a fault on the safety related equipment and the redundant AC isolation valves would be available (this MCC feeds mostly DC isolation valves). The team determined that the lack of coordination was not safety significant; however, this concern was considered to be a weakness relative to breaker/fuse coordination.

2.2.9 Panel D 33 Coordination

Calculation NO. 802-012-E-1 and Impell coordination study NO. NX17152-2 indicated close coordination between a 100 amp breaker feeder from Panel D 31 and a 30 amp fuse load supply from panel D 33, the breaker feeder load. However, no tolerances were indicated to give confidence of coordination. The 30 amp fuse supplies a 1E load similar to other fuses in the panels. A fault at the load side of the 30 amp fuse will also trip the panel D 33 100 amp supply breaker, thus cutting power to all loads supplied from panel D 33. The circuit breaker will sense the fault current before .01 sec, and start the opening action. The breaker cannot reset the trip once started and will continue to open as the 30 amp fuse blows. The actual breaker trip will most likely occur after the 30 amp fuse blows. Therefore, there is no coordination between the breaker and fuse. NSP justified the mis-coordination based on their classification of this arrangement as a single failure. In addition, the other division of power was not affected. The teams considered this to be a weakness relative to breaker/fuse coordination.

2.2.10 Conclusions

The team determined that in general the performance of the DC systems was adequate. Design attributes were retrievable and verifiable. Calculations were acceptable; however, more attention needs to be paid to breaker/fuse coordination.

2.3 Mechanical Systems

The team reviewed and evaluated the adequacy of the mechanical system design for the support of the EDS. The support mechanical systems (SMS) included the EDGs, EDG support systems, and the EDS heating/ventilation and air conditioning (HVAC) systems. The review included a system walkdown and examination of SMS licensing, engineering, vendor, purchasing, and plant operations documents including USAR and TS; selected modifications and safety evaluations; mechanical system calculations; process and instrumentation diagrams (P&ID); pump performance curves and motor data sheets; HVAC flow diagrams (FDs); EDG manufacturer technical manuals, selected schematics, and detailed component drawings; procurement specifications for the EDG; operations manuals; and annunciator and abnormal operating procedures.

The team also observed the monthly tests of both EDGs conducted according to Test No. 0187-1(2), "Standby Generator/EDG Emergency Service Water Monthly Tests," Rev. 10. The licensee conducted the tests satisfactorily in a competent and professional manner.

2.3.1 EDG ESW Crosstie

The team was concerned that a crosstie between the non safety related service water (SW) and the EDG emergency service water (ESW) would degrade the reliability of the EDG ESW system. The purpose of the crosstie, as described in the USAR, was to provide a backup supply of water to the EDG ESW system. The supply was through a fail-open air-operated valve that opened when the EDG received a start signal. The EDG ESW pumps start simultaneously. Since, in parallel operation, the SW pump was stronger than the EDG ESW pump, the EDG ESW pump could operate at low flow. If flow were low enough, hydraulic instability or impeller recirculation could occur, resulting in pump damage from vibration, excessive forces on the impeller, or cavitation. Therefore, in an emergency the ESW pump might be degraded sufficiently by a delayed loss of SW and, when required, would be unable to provide the required flow of water. As a result, the EDG could overheat and require shutdown. The licensee was aware of this condition and had taken special care to close the crosstie between SW and EDG ESW during testing. However, there was no specific requirement in the licensee's emergency or EDG ESW abnormal operating procedures to close the crosstie. In response to the team's concern, the licensee committed to closing the crosstie during normal operations. The licensee completed these actions on November 9, 1990. The team considered the resolution of the concern adequate.

2.3.2 EDG ESW Low Flow

The team was concerned that the operators would not be aware of a low EDG ESW flow condition in which the EDG could overheat and require shutdown. The EDG ESW low flow setpoint was 175 GPM while the minimum required flow was 360 GPM. In response to the team's concern, the licensee changed the low flow set point to 360 GPM. The team considered the resolution of the concern adequate.

2.3.3 EDG Fuel Oil Storage Requirements

The team was concerned that the EDG fuel oil (EFO) minimum storage tank requirements were incorrectly calculated. The USAR required the storage tank to "provide sufficient fuel for at least one week of full load operation of one unit." The consumption rate used to decide the total EFO requirement was 186 gallons per hour (GPH). The team noted that this rate assumed 30 degree API gravity fuel oil. The EFO specification allowed up to 38 degree API gravity. The consumption rate for 38 degree API gravity was estimated at 192.5 GPH. This difference would increase the storage requirement by 1092 gallons. In response to the team's concern, the licensee raised the minimum storage level in the tank to allow a consumption rate of 200 GPH. The licensee also reviewed storage tank level records and determined that levels had been maintained greater than the new minimum requirement. The team concluded that the plant had not been in an unsafe condition and considered the resolution to the concern adequate.

2.3.4 Division II 250Vdc Battery Room Temperature

The Division II 250Vdc battery room temperature is required to be maintained above 60°F. The team found that under certain emergency conditions (high radiation or toxic chemical emergency mode) failure of the electric heaters could go undetected as no temperature indication or alarm is available to the operator. The battery capacity could be in an unanalyzed condition. The licensee agreed with the concern and took short term compensatory actions. The battery room will be inspected and the temperature verified three times during every shift. Pending NRC's review of the licensee's permanent solution to this concern, this issue was considered an open item (263/90018-01).

2.3.5 Non-Seismic Ductwork in the Battery Rooms

During a walkdown, the team observed the non-seismic nature of the ductwork installation in battery room No. 13. The team questioned the potential safety consequences of a seismic event and its effect on the batteries. At the exit, the licensee indicated that a Seismic Qualification Utility Group (SQUG) walkdown was performed and the ductwork was analyzed and found capable of withstanding a seismic event. The team reviewed the results of the licensee's analysis and found it acceptable. Per NRR, a review of similar seismic concerns will be included in the resolution to Unresolved Safety Issue (USI) A-46.

2.3.6 Non-Seismic Heating Installation in the EDG Rooms

During the walkdown of the EDG building, the team identified the potential for degradation of the EDG equipment due to failure of the steam heating system in the EDG rooms during a seismic event. The team questioned the potential safety consequences if the steam piping were to fail and live steam was introduced into the EDG rooms. The licensee indicated that this concern had also received a SQUG walkdown and analysis and that the piping was considered acceptable. The team reviewed the results of the licensee's analysis and found it acceptable.

2.3.7 Conclusions

The team determined that, in general, the performance of the mechanical support systems was acceptable. The knowledge and expertise of the system engineers was considered a strength.

3.0 Maintenance

The team evaluated corrective, preventive, and predictive maintenance to determine effectiveness of the maintenance process in maintaining safety related and BOP components important to safety in operable/functional condition. The team also assessed the capability of supporting organizations to provide technical support to maintenance. The team reviewed and evaluated completed work requests, design changes, procedures, commercial grade dedication program, fuse control program, work request (WR) backlog, post maintenance testing, NPRDS, corrective action programs, vendor manuals, corporate and plant engineering support, QA/QC, and management involvement in the maintenance process.

The team walked down selected electrical components and equipment in the Residual Heat Removal (RHR) and Core Spray (CS) systems to determine maintenance, engineering, and support group involvement in assuring design and configuration control. The inspection included examination of schematic, wiring and logic diagrams, as-built configuration control, cable separation, thermal overload and motor operated valves (MOV) torque switch settings, use of commercial grade items, and material condition of electrical equipment. The team inspected selected control and cable spreading room cabinets and panels, the remote shutdown panel, 4KV and 480Vac switch gear, 480Vac MCCs, distribution panels, emergency lighting, RHR and Low Pressure Coolant Injection (LPCI) valves and pump areas and DG rooms.

3.1 Preventive Maintenance

The team determined that the existing preventive maintenance (PM) program and process was not integrated/consolidated to do effective and controlled maintenance. The licensee relied heavily on system engineers to determine the equipment and schedule of PM activities (except TS formalized surveillances). An integrated maintenance schedule was not established; therefore, the team could not assure that all safety related and balance of plant (BOP) components important to safety were included in the maintenance scope and maintained appropriately. The licensee's philosophy was to not perform PMs during plant operation. The team determined that preventive maintenance was not formally scheduled or completed on some safety related and BOP MCC units. Examples included molded case breaker inspection and electrical bus work such as, cleaning, inspection for insulation degradation and tightening of bus work connections on 4KV, 480Vac switchgear and MCCs. In addition, safety related control relays and the overspeed mechanism on the Reactor Core Isolation Cooling (RCIC) turbine were not included in the PM program for recommended PMs. Also, PMs, including vendor recommended PMs on safety related MCCs B34 and B44, were not performed since initial installation in 1983. When requested by the team, the licensee could not locate the last documented completion of PM task No. PM 4140. This task was originally issued in 1974 to inspect RHR SW pump Nos. 11, 12, 13, and 14 motor and pump components and connections for excessive vibration, noise, oil or grease leakage, corrosion or oil quality. The team considered the above examples evidence of weaknesses relative to preventive maintenance; however, no examples of hardware failure were found during of this inspection.

3.2 Corrective Action and Trending

A formal trending program of repeat component failures did not exist. The team noted that LERs and Component Failure Analysis Report (CFAR) reports indicated excessive relay failures at Monticello. The last three available CFAR reports reported higher than normal/industry average failure rates for G.E. CR120A relays. LER 90-02 identified seven similar failures in the past; but, the specific root cause for the failures identified random failure or "normal age and wear." A documented root cause analysis was not available for review; however, the licensee subsequently informed the team that the relays would be replaced during the next refueling outage. Review of NPRDS reported failures indicated that even though the licensee attributed the root cause of many failures to "normal age and wear," the licensee did not establish a program to address component failures that were due to age or wear. The team considered this a weakness relative to corrective action and trending.

3.3 As-Built Evaluation/Inspection

The team identified approximately twenty discrepancies that existed between the design drawings and field installation in safety related panels including remote shutdown panel C292; RHR, CS and ADS panel C33; Reactor Water Cleanup and Recirculation Benchboard C04; and safety related 480V MCC B 43. The following deficiencies were noted:

a. The team determined that terminations on terminal points and control relays shown on CS and RHR drawings did not conform to installed wiring, and a splice not approved by plant procedures or industry practices was observed in the MCC.

b. Three fuses in remote shutdown panel C292 were shown on drawings as 10A spares while the field used 5A and 1.6A fuses. The field installation was correct. The licensee installed the fuses in 1987 per modification No. 87Z028 and the drawing had not been updated. The licensee is currently updating the drawing.

c. Modifications that were installed in the field were not reflected on the as-built (controlled) drawings contained in the Shift Supervisor's office. The operators use these drawings in emergency conditions and they are also used by maintenance and engineering staff to verify design drawings before using them in the field and for design purposes. The licensee issued

Nonconforming Item Report No. 90-048 to document and resolve the identified deficiencies. The licensee subsequently notified the team that the wiring of the conductors on relay Nos. 10A-92b, 10A-24b, and 10A-26b did not conform to the applicable design drawings and that an as-built walkdown of the relay wiring must be done to determine the effect of the wiring errors. Pending the licensee's walkdown and evaluation of the findings, this item is considered unresolved (263/90018-02).

d. The team identified many examples of terminations containing three conductors on a single terminal point. Present NSP practices do not allow three conductors on a single terminal point unless a stud is installed. The licensee is evaluating this issue.

e. The team noted that wire nuts were used in MCC 33A, compartment B3317, to splice the black and white conductors of cable Nos. FS20895/1 and B3317-C20/1. Procedure MWI-8-M-4.06, Revision 0, "Conductor Termination and Splicing" did not address wire nut applications. The wire nuts were subsequently replaced on November 30, 1990.

3.4 Overload and Torque Switch Setting

The team noted that documented engineering sizing calculations and criteria for thermal overload heaters did not exist. Also, complete records or tracking mechanisms for MOV torque switch settings were not available for review. The licensee is currently establishing documented criteria for sizing thermal overloads and torque switch settings and evaluating all existing safety related applications. The team considered the lack of documentation for thermal overload heaters and torque switch settings a weakness.

3.5 Conclusion

The team determined that the maintenance process at Monticello was effectively implemented by a knowledgeable and dedicated staff. However, improvement in the scope and management of the maintenance process is needed as evidenced by the weaknesses identified by the team.

The team noted the following program strengths:

a. The maintenance backlog was low.

b. The electrical maintenance and engineering staff have extensive experience and appeared to be very dedicated with a sense of ownership.

c. Rework activities were low.

d. The plant's material condition and housekeeping were very good.

e. Failure rates of 4KV breakers were low.

4.0 Surveillance and testing

The team evaluated surveillance and post-modification testing including the involvement of engineering and management in the development of testing requirements.

4.I.1 Setting of Degraded Grid Voltage Relays

The team determined that the setpoints for the degraded voltage protection relays contained in Table 3.2.6 of the plant's TS were not based on a setpoint methodology that addressed all known errors associated with this instrumentation.

Basis 3.2 of the plant's TS stated that deviations in the setpoint caused by inherent instrument error, operator setting error, drift, etc. have been accounted for in various transient analyses and the actual trip setting for these degraded voltage relays may vary by no less than -18 volts. Further, on page 71a, the TS state that "a violation to this specification is assumed to occur when a device is knowingly set outside of the limiting trip setting or when a sufficient number of devices have been affected by any means such that the automatic function is incapable of operating within the allowable deviation. . . . ."

Monticello Test #0302, "Safeguard Bus Degraded Voltage Protection Relay Unit Calibration," stated that the permissible as-left calibration tolerance was ±17.5V. In addition to this potential operator setting error, the trip setpoint for these relays must account for other errors such as drift. If the operator sets the actual trip setpoint at -17.5 volts, only 0.5 volts can be allotted for these other errors. Historically, over one three month period actual test data indicated that these relays had a drift of up to -30.1 volts. This exceeded the 0.5 volts allotted for drift. Additionally, the relay manufacturer has identified other relay tolerances that could add another -25V to the actual setpoint.

Since the maximum deviation, -18V, allowed by the TS is not large enough to account for these additional errors and the licensee lacks setpoint methodology to establish a setpoint with all known errors included, the relays may not detect degraded voltage conditions and transfer safety loads to the EDGs at a voltage level adequate to ensure proper safety equipment performance or to prevent safety equipment damage. Pending NRC review of the licensee's evaluation of this concern, this is considered an unresolved item (263/90018-03(DRS)).

4.1.2 Service Test of Batteries

The team determined that the licensee's battery service test procedures did not ensure batteries were tested in an as-found condition. Before conducting battery service tests on safety related batteries, the licensee's test procedures direct test personnel to examine inter-cell connectors and connections at cell posts for corrosion and tightness. If a battery condition was unacceptable, the test of that battery was deferred for further maintenance. Several service test procedures, such as No. 4520 PM, also allow the technician to select two inter-cell connections at random and remove, clean and torque them before the test start to establish a reference for inter-cell connection quality. Further, service test procedures do not ensure that the battery to be tested was not equalized within seven days before the test.

The above shortcomings do not follow the guidance contained in IEEE Standard 450-1987, "Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," which was listed as a reference in the licensee's service test procedures. Results obtained from using the test procedures may not reflect the true as-found condition of the battery under test or the quality of previous maintenance. Therefore, this practice defeats the purpose of the service test surveillance required by the plant's TS and was considered a weakness by the team.

4.1.3 Bus Transfer Testing

The team determined that the testing program did not verify the transfer of transformer No. 1R to transformer No. 1AR and subsequent loading of 1AR by the safety buses. The 1AR transformer has limited capacity and functions as a backup source for the safety buses. Test Procedure Nos. 0036-1, 0036-2, and 0189-01 tested portions of the transfer logic and the load shedding circuits. However, the logic portion tested was the transfer from 1AR to the EDGs, if 1AR was not available. The testing did not verify the transfer of 1R to 1AR and subsequent loading of 1AR transformer by the emergency buses. The Monticello TS (3.9.A.1.b) stated, in part, that at least two NSP transmission lines, associated switchgear, and at least two offsite power sources are fully operational and energized to carry power to the plant 4160Vac buses. The licensee is meeting the intent of the above specification by having more than two transmission lines available, testing the associated switchgear and maintaining 1R and 1AR energized. The team acknowledged that the plant is within its safety analysis which takes credit for the safe shutdown of the plant (LOCA) concurrent with a loss of offsite power using the EDGs. However, the team was not confident that a successful transfer to the 1AR transformer could occur, and that 1AR and its associated switchgear were capable of carrying power to the plant's 4160Vac buses. The licensee initiated Action Item No. 14 to determine if the slow bus transfer logic will successfully transfer from the 1R to the 1AR transformer and to determine if the 1AR transformer was capable of carrying the plant's 4160Vac emergency loads. Pending the NRCs review of Action Item No. 14, this is considered an unresolved item (263/90018-04(DRS)).

4.1.4 EDG Instrumentation Testing

The team's review of EDG process instrumentation, sensing relays, and timing relays produced four devices, Nos. TS-7194 and TS-7195 (EDG immersion heater control), and PS-7222 and PS-7223 (crank case pressure), that had setpoints that differed from the recommended manufacturer settings. However, the licensee provided adequate documentation to support the setpoint changes. The team also identified the following EDG relays that were not included in the current calibration program:

Relay	Type	Function
40V	Sensing	Field voltage
ES	Sensing	100 RPM engine speed
LWD	Timing	Low water relay
SCR	Timing	Speed checking

The licensee performed an analysis to determine the impact on the EDGs if these relays were out of tolerance. The analysis adequately proved that the relays would perform their intended function. In addition, successful testing of the EDGs has qualitatively demonstrated the operability of the relays. The licensee committed to include these relays in future testing.

4.1.5 EDG Process Instrumentation Calibration

During the review of calibration records for all EDG process instruments, the team identified two pressure indicators (PI-7002 and PI-7005) that were left exceeding their as-left calibration tolerances. The indicators were calibrated during the last refueling outage (August 1989) in Procedure No. 7180, "Diesel Generator System Instrument Maintenance Procedure." Instrument and control (I&C) supervision and the system engineer had not been informed of the out-of-calibration status of these indicators. In addition, nonconformance report Nos. 90-043 and 90-044 identified additional examples where No. 12 EDG base tank level switches and the No. 12 EDG air start circuit timing relay were left exceeding their as-left calibration tolerances since the last refueling outage (calibrated in Procedure No. 1052-1, "11 and 12 Diesel Generator Time Delay Relay and Auxiliary Systems Test"). The following is a list of the desired instrument calibration values:

Instrument	Calibration Tolerance	As-Left Value
PI-7002	300 ± 3 psig	305 psig
PI-7005	160 ± 1.6 psig	156 psig
LS-721I Trip	255-345 gallons	380 gallons
LS-7215 Trip	153-207 gallons	240 gallons
Reset	191-259 gallons	270 gallons
STL01	5.5+1, -0 seconds	5.1 seconds

In the above examples, no engineering evaluation or documentation of the instruments' out-of-calibration status were performed at the time of the calibration. Failure of the licensee to assure that test requirements have been satisfied is considered a violation of 10 CFR 50, Appendix B, Criterion XI (263/90018-05(DRS)).

The licensee has evaluated each affected instrument and determined there was no impact on EDG operability.

4.1.6 Conclusions

Post-modification testing was adequate and design objectives were met prior to the equipment being returned to service. The plant had a well-structured program in place for performing surveillance testing of EDS equipment and components; however, a number of weaknessed were identified.

5.0 Engineering and Technical Support

During the inspection, the team evaluated NSP's E&TS capability. The team reviewed the licensee's temporary modification (bypass control) program, permanent modification program, portions of the station's discrepancy management program, 10 CFR 50.59 evaluation program, and QA/QC program. In addition, the team reviewed the as-built/drawing reconciliation program and the audit findings of the licensee's internal QA audit of 1989.

5.1.1 Bypass Control

The team noted that the procedure for bypass control does not direct plant personnel to update information on the control room drawings to reflect configuration changes caused by the installation of bypasses. The team was concerned that if drawings were not timely updated, the capability of the plant operators to trouble-shoot problems or mitigate events could be affected. The unrevised set of drawings could also create problems during the alignment of plant systems for routine testing or maintenance.

This concern is similar to the concern raised in Section 3.4 and is considered a further example of a weakness relative to drawing control.

5.1.2 Bypass Number Reassignment

The team's review indicated that after each calendar year, plant personnel closed all active bypasses by signing the required blocks. The licensee then reactivated the bypasses by assigning serial numbers for the new year. The licensee informed the team that this activity had been performed for the last 10-12 years, although the bypass control procedure did not direct personnel to perform this activity. Also, the reactivated bypasses did not cross reference to old serial numbers. The team found the following examples:

a. Bypass 90-10 was originally installed on 11/4/89, although the bypass form indicated that it was installed on 1/2/90.

b. Bypass 90-15 was originally installed on 6/26/89, although the bypass form indicated that it was installed on 1/3/90.

c. Bypass 90-5 was originally installed on 8/31/88, although the bypass form indicated that it was installed on 1/1/90.

The team was concerned that the current bypass numbering system, without cross references, could create configuration control problems. The team considered this to be a weakness relative to configuration control.

5.1.3 Trouble Shooting Procedures

The team identified that technicians were not providing details of actual work done or parts replaced while performing trouble shooting activities. The team noted that the plant did not have procedures to direct and effectively control activities relating to the troubleshooting activities. Subsequently, the licensee informed the team that they were aware of the above problems relating to these troubleshooting activities and had initiated corrective actions. These actions included performing quarterly training to improve the knowledge of requirements and making several revisions to the work request authorization (WRA) process and to the related forms. The licensee expected to complete these corrective actions in the near future. The team considered the resolution to this concern to be adequate.

5.1.4 Participation of QA/QC in Plant Activities

The team found that a weekly statistical report describing completed and future QC involvement as well as percentage completed was displayed at QA supervisor's office. The team was concerned that any technician who looked at the weekly statistical report could predict future QC involvement. Subsequently, the licensee informed the team that the practice of displaying the weekly statistical report out in public areas had been discontinued and the weekly reports will be kept inside the QC supervisor's office.

5.1.5 Conclusions.

In general, the team found that the licensee provided adequate E&TS to the operational staff. The following strengths were noted:

a. Licensee personnel were highly qualified and had substantial experience in their fields of expertise.

b. Appropriate, effective root cause analyses were generally performed in a timely manner by engineers trained in root cause analysis techniques that followed INPO guidelines.

c. Technical staff personnel had required training and must pass the senior reactor operator (SRO) system test and walk-through on the applicable systems.

6.0 General Conclusions

Based on the inspection sample, the team did not identify any operability concerns, and concluded that the design of the EDS was generally acceptable. The emergency power sources were sized properly and adequate voltage was available to essential buses to accommodate EDS loads. With a few exceptions, the protection and coordination of the protective equipment was adequate. The scope of the EDS testing was appropriate. Technical support for the EDS from corporate and site personnel was adequate. The staff was very knowledgeable and competent.

The team conducted an exit meeting on November 2, 1990, at Monticello to discuss the major areas reviewed during the inspection, the weaknesses observed, and the inspection findings. NRC personnel and licensee representatives who attended this meeting are documented in Appendix A of this report. The team also acknowledged commitments made during the inspection. The licensee did not identify any documents or processes as proprietary.

7.0 Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the team, and which involve some action on the part of the NRC or licensee or both. An open item disclosed during this inspection is discussed in Paragraph 2.3.4.

8.0 Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during this inspection are included in Paragraphs 3.3.c, 4.1.1 and 4.1.3.

APPENDIX A

Northern States Power Company

K. L. Albrecht, Director, Power Supply QA
J. Anderson, System Engineer, Technical Engineering
D. Antony, General Manager, Monticello Site
M. Clarity, Assistant to the Plant Manager
G. Crosby, Quality Supervisor, Power Supply QA
B. Day, General Superintendent, Engineering and Radiation Protection
S. Engelke, Superintendent, Technical Engineering
S. Hammer, Superintendent, Operations Engineering
W. Hill, Plant Manager
J. Hoffman, Prairie Island
P. Johnson, Manager, Nuclear Projects Department
D. Jones, Electrical Engineer
T. Jones, Specialist, Power Supply QA
P. Kamman, Manager, Nuclear Operations QA
D. Krech, Quality Supervisor, Power Supply QA
D. Larsen, General Superintendent, Engineering
K. Mustaphi, Consulting Engineer, Substation Transmission Engineering
D. Musolf, General Manager, Nuclear Support Group
G. Neils, Executive Vice President
D. R. Nordell, Senior Design Standards Engineer
D. E. Nevinski, General Superintendent, Operations
D. Olson, Superintendent, Electrical Engineer
L. Pudlick, Lead Engineer, Technical Engineer
T. A. Pickens, Principal Licensing Engineer
S. Porter, Production Engineer
C. Schibonski, Superintendent, Design Standards
K. Skillingstad, Supervisor, Technical Services
M. Sleigh, Quality Engineer
R. Van Dell, Lead Production Engineer
L. O. Wilkerson, Acting Superintendent, Quality Engineering

U.S. Nuclear Regulatory Commission

T. O. Martin, Director, Division of Reactor Safety, RIII
R. N. Gardner, Chief, Plant Systems Section (PSS), RIII
R. A. Westberg, Team Leader, Reactor Inspector, RIII
D. S. Butler, Engineer, RIII
S. Falevits, Reactor Inspector, RIII
W. A. Slover, Reactor Inspector, RIII
R. W. DeFayette, Chief, Division of Reactor Projects, RIII
S. P. Ray, Resident Inspector, RIII
S. V. Athavale, Electrical Engineer, NRR
F. H. Burrows, Electrical Engineer, NRR
J. Jacobson, Special Inspection Branch, NRR
W. O. Long, Project Manager, NRR
L. Lazic, Consultant, NRC/Atomic Energy of Canada Limited (AECL)
O. S. Mazzoni, Consultant, NRC/AECL
P. Pattantyus, Consultant, NRC/AECL

APPENDIX B

FINDING: Division II 250 v Battery Room Temperature
(Section 2.3.4 of Report)

DESCRIPTION:

Under certain emergency conditions (high radiation or toxic chemical emergency mode) failure of the electric heaters cold go undetected because no temperature indication or alarm is available to the operators.

TECHNICAL REFERENCES:

1. Operations Manual B.8.13 Revision 0, "Heating, Ventilation, and Emergency Filtration Train"

2. P&I Diagram NF 61716 Revision F, "Monticello Generating Plant Main Control Room H&V/EFT System"

SAFETY SIGNIFICANCE:

For the above postulated conditions, due to the temperature, the batteries could be in an unanalyzed condition.

FINDING: As-built Deficiencies (Section 3.4.c of Report)

DESCRIPTION:

Twenty discrepancies were identified between the design drawings and field installation in the following safety related panels: remote shutdown panel C292; RHR, CS and ADS panel C33; reactor water cleanup and recirculation benchboard C04; and 480Vac MCC B43.

TECHNICAL REFERENCES:

10 CFR 50, Appendix B, Criterion VI, "Document Control"

SAFETY SIGNIFICANCE:

The operators use these drawings (in the shift supervisor's office) during emergencies and plant line-ups. The drawings are also used by the engineering staff for design purposes.

FINDING: Lack of set point methodology for the degraded grid voltage relays (Section 4.1.1 of Report)

DESCRIPTION:

The maximum deviation of -18v allowed by the technical specifications was not large enough to account for addition errors, such as operator setting error and drift. The licensee lacks a setpoint methodology to establish a setpoint that accounts for all the known uncertainties.

TECHNICAL REFERENCES:

1. Technical Specification Basis 3.2 and Table 3.2.6.
2. Test No. 0302, "Safeguard Bus Degraded Voltage Protection Relay Unit Calibration"

SAFETY SIGNIFICANCE:

The relays may not detect degraded conditions and transfer safety loads to the EDGs at a voltage level adequate to ensure proper safety equipment performance or to prevent safety equipment damage.

FINDING: Bus Transfer Testing (Section 4.1.3 of Report)

DESCRIPTION:

The testing program did not verify the transfer of transformer No. 1R to transformer No. 1AR and subsequent loading of 1AR by the safety buses.

TECHNICAL REFERENCE:

1. Technical Specification No. 3.9A.1.b

2. Test Procedure Nos. 0036-1, 0036-2, and 0189-01

SAFETY SIGNIFICANCE:

Successful transfer of 1R to 1AR and the subsequent loading of 1R by the safety buses may not occur which could affect the safe shutdown of the plant.

NRC FORM 766
(6-83)
IE MC 0535

U.S. NUCLEAR REGULATORY COMMISSION

INSPECTOR'S REPORT

Office of Inspection and Enforcement

PRINCIPAL INSPECTOR *(Name, last, first, and middle initial)*: Westberg Rolf A

REVIEWER: Gardner, Donald N.

INSPECTORS: Butler, Falevits, Stover

LICENSEE VENDOR: Northern States Power Company Monticello Nuclear Generating Station

TRANSACTION TYPE:
☒ I – INSERT
☐ M – MODIFY
☐ D – DELETE
☐ R – REPLACE
1

DOCKET NO. (8 digits) OR LICENSE NO. (BY PRODUCT) (13 digits): 05000263
2 … 14

REPORT NO.	SEQ.	NEXT INSPEC. DATE MO.	YR.
90018	A		
	B		
	C		
	D		
15 … 18			

PERIOD OF INVESTIGATION/INSPECTION

FROM MO.	DAY	YR.	TO MO.	DAY	YR.
10	01	90	11	02	90
20		25	26		31

INSPECTION PERFORMED BY:
☒ 1 – REGIONAL OFFICE STAFF
☐ 2 – RESIDENT INSPECTOR
☐ 3 – PERFORMANCE APPRAISAL TEAM
☐ OTHER
32

ORGANIZATION CODE OF REGION/HQ CONDUCTING ACTIVITY *(See IEMC 0530 "Manpower Reporting—Weekly Manpower Reporting," for code.)*

REGION	DIVISION	BRANCH
3	3	1
33	34	35

REGIONAL ACTION (Check one box only):
☐ 1 – NRC FORM 591
☒ 2 – REGIONAL OFFICE LETTER
36

TYPE OF ACTIVITY CONDUCTED (Check one box only):
☐ 02 – SAFETY
☐ 03 – INCIDENT
☐ 04 – ENFORCEMENT
☐ 05 – MGMT. AUDIT
☐ 06 – MGMT. VISIT
☒ 07 – SPECIAL
☐ 08 – VENDOR
☐ 09 – MAT. ACCT.
☐ 10 – PLANT SEC.
☐ 11 – INVENT. VER.
☐ 12 – SHIPMENT/EXPORT
☐ 13 – IMPORT
☐ 14 – INQUIRY
☐ 15 – INVESTIGATION
37-38

INSPECTION/INVESTIGATION FINDINGS (Check one box only):

A	B	C	D	
				1 – CLEAR
☒				2 – VIOLATION
				3 – DEVIATION
				4 – VIOLATION & DEVIATION

39

TOTAL NUMBER OF VIOLATIONS AND DEVIATIONS:

A	B	C	D
10			

40-41

ENFORCEMENT CONFERENCE HELD: A ☐ B ☐ C ☐ D ☐ 1 – YES
42

REPORT CONTAIN 2.790 INFORMATION: A ☐ B ☐ C ☐ D ☐ 1 – YES
43

LETTER OR REPORT TRANSMITTAL DATE:

NRC FORM 591 OR REG. LETTER ISSUED MO.	DAY	YR.	REPORT SENT TO HQ. FOR ACTION MO.	DAY	YR.
44		49	50		55

MODULE INFORMATION

REC-ORD TYPE	MODULE NUMBER INSP. NUMBER	PHASE	MANUAL CHAPTER	PROCEDURE NUMBER	LEVEL	SEQ.*	PRIORITY	DIRECT INSPECTION EFFORT IN STAFF HOURS EXPENDED THIS INSPECTION	PERCENTAGE COMPLETED TO DATE	STATUS	MODULE REQ. FOLLOWUP PHASE	MANUAL CHAPTER	PROCEDURE NUMBER	LEVEL
B	01	5	30	703		A								
Entrance/Ext						B								
						C								
						D								
B	02	5	25	107		[✓ A]								
EDSFI						B								
						C								
						D								
B						A								
						B								
						C								
						D								
B						A								
						B								
						C								
						D								
1	2 3	4	5		10		12	13 … 15	16 … 18	19	20	21		26

MODULE INFORMATION

REC-ORD TYPE	MODULE NUMBER INSP. NUMBER	PHASE	MANUAL CHAPTER	PROCEDURE NUMBER	LEVEL	SEQ.*	PRIORITY	DIRECT INSPECTION EFFORT IN STAFF HOURS EXPENDED THIS INSPECTION	PERCENTAGE COMPLETED TO DATE	STATUS	MODULE REQ. FOLLOWUP PHASE	MANUAL CHAPTER	PROCEDURE NUMBER	LEVEL
B						A								
						B								
						C								
						D								
B						A								
						B								
						C								
						D								
B						A								
						B								
						C								
						D								
B						A								
						B								
						C								
						D								
1	2 3	4	5		10		12	13 … 15	16 … 18	19	20	21		26

* CIRCLE SEQUENCE IF VIOLATION OR DEVIATION

NRC FORM 766 A
(11 8)
R MC 0535

INSPECTOR'S REPORT
(Continuation)
Office of Inspection and Enforcement

DOCKET NO. (8 digits) OR LICENSE NO. (BY PRODUCT) (13 digits): 05000263

REPORT NO.: 90018
SEQ.: A

MODULE NUMBER: 25107

SUP I

VIOLATION SEVERITY OR DEVIATION: 1 ☐ 2 ☐ 3 ☐ 4 ☒ 5 ☐ 6 ☐ "D" ☐

SITE RELATED: A ☐ B ☐ C ☐ D ☐

VIOLATION OR DEVIATION (*Enter up to 2400 characters for each item. If the text exceeds this number, it will be necessary to paraphrase. Limit lines to 50 characters each.*)

10 CFR 50, Appendix B, Criterion XI, requires that test results be documented and evaluated to assure that test requirements have been satisfied.

Contrary to the above, since August 1989, no evaluations of acceptability were made when two emergency diesel generator (EDG) pressure indicators, the No. 12 EDG air start circuit timing relay, and both EDG basetank fuel oil level switches were left in a condition that exceeded their as-left calibration tolerance.

Prior to the end of the inspection, the licensee evaluated each of the above instruments and determined that there was no impact on EDG operability.

OUTSTANDING ITEM [illegible] (OIL) TRACKING FORM

Submitted by: R Westberg

Sec. Chief Approval Brent Clayton for RWD

Item No.	Type Code	Func. Area
263/90018-05 (Unit 1)	V4	1
Original Inspector	Resp. Sec.	Note
R. Westberg	PSS_	______

Responsible Inspector	Closed	Final Report No.
PSS	__ / __ /__	______

Interim Insp. Reports ______ ______ ______ ______ ______

Followup Date

__ /__/ __

Remarks:

Since August 1989, no evaluations of acceptability were made when two EDG pressure indicators, the No. 12 EDG air start circuit timing relay, and both EDG basetank oil level switches were left in a condition that exceeded their as-left calibration tolerance.

Status Code

OUTSTANDING ITEM [illegible] (OIL) TRACKING FORM

Submitted by: R Westberg

Sec. Chief Approval Forest Clayt for RWD

Item No.	Type Code	Func. Area
263/90018-04 (Unit 1)	UNR	1
Original Inspector	Resp. Sec.	Note
R. Westberg	PSS_	________
Responsible Inspector	Closed	Final Report No.
PSS	__ / __ /__	________

Interim Insp. Reports ________ ________ ________ ________ ________

Followup Date

__ /__/ __

Remarks:

The surveillance test program did not verify the transfer of the the 1R transformer to the the 1AR transformer and subsequent loading of 1AR by the safety buses.

Status Code

OUTSTANDING ITEM[illegible] (OIL) TRACKING FORM

Submitted by: R Westberg

Sec. Chief Approval Brent Clayton for RWB

Item No.	Type Code	Func. Area
263/90018-03 (Unit 1)	UNR	1
Original Inspector	Resp. Sec.	Note
R. Westberg	PSS_	______

Responsible Inspector	Closed	Final Report No.
PSS	__ / __ /__	______

Interim Insp. Reports ______ ______ ______ ______ ______

Followup Date

__ /__/ __

Remarks:

The degraded voltage relay setpoint does not account for all the know uncertainties; there fore the relays may not detect a degraded voltage condition and transfer the loads to the EDGs.

Status Code

OUTSTANDING ITEM [illegible] (OIL) TRACKING FORM

Submitted by: R Westberg

Sec. Chief Approval for RWD

Item No.	Type Code	Func. Area
263/90018-02 (Unit 1)	UNR	1
Original Inspector	Resp. Sec.	Note
R. Westberg	PSS_	________

Responsible Inspector	Closed	Final Report No.
PSS	__ / __ /__	________

Interim Insp. Reports ________ ________ ________ ________ ________

Followup Date

__ /__/ __

Remarks:

Wiring of the conductors on relay Nos. 10A-92b, 10A-24b, and 10A-26b did not conform to the appliocable design drawings.

Status Code

OUTSTANDING ITEM [illegible] (OIL) TRACKING FORM

Submitted by: R Westberg

Sec. Chief Approval Forest Clough for RWD

Item No.	Type Code	Func. Area
263/90018-01 (Unit 1)	0	1
Original Inspector	Resp. Sec.	Note
R. Westberg	PSS	
Responsible Inspector	Closed	Final Report No.
PSS	__ / __ /__	

Interim Insp. Reports

Followup Date

__ /__/ __

Remarks:

Under certain emergency conditions (high radiation or toxic chemical emergency mode) failure of the electric heatersa in the Div II 250Vdc battery room could go undetected as no temperature indication or alarm is available to the operators.

Status Code

RP 1208

INSPECTION PLAN

Facility: Monticello
Inspection Report No: 90018
Inspection Date(s): 10/1 - 11/2/90
Resident Notified: YES
Inspection Type: Core ____ Regional Init. ____ Team X Reactive ____
Other (specify) EDSFI
Announced X Unannounced ____
SALP Weaknesses addressed ____

Inspection Focus (SALP Weakness, Core Program, Regional Initiative, Event Followup)	Module/TI No.	SALP Area/ Rating	Priority No.	Open Item No. (OIL)
(SEE Attached Plan)				

Plan Prepared By: Rolf A. Westberg Date: 10/11/90
Lead Inspector

Plan Approved By: Date: 10/11/90
Section Chief

Plan Reviewed By: Date: 10/11/90
Project Section Chief
(or DRS/S Branch Chief)

Attachment C
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