U.S. NUCLEAR REGULATORY COMMISSION
REGION I

REPORT/DOCKET NO.	50-410/93-81
LICENSE NO.	NPF-69
LICENSEE:	Niagara Mohawk Power Corporation
FACILITY NAME:	Nine Mile Point Unit 2
INSPECTION DATES:	November 29, 1993 through December 17, 1993, and January 24-28, 1994
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Areas Inspected: Announced team inspection by regional and contracted personnel to review the functionality of Nine Mile Point Unit 2 electrical distribution system.

Results: As described in the Executive Summary.

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EXECUTIVE SUMMARY

During the period between November 29, 1993, and January 28, 1994, a Nuclear Regulatory Commission (NRC) inspection team conducted an electrical distribution system functional inspection (EDSFI) at the Nine Mile Point Unit 2 (NMP2). The inspection was performed to determine the adequacy of the Niagara Mohawk Power Corporation (NMPC) self-assessment, and whether the electrical distribution system (EDS) at NMP2 was capable of performing its intended safety functions as designed, installed, and configured. This inspection also included a review of NMPC response to the deficient condition that the high pressure core spray (HPCS) system injection valve failed to open during testing as reported in licensee event report (LER) 93-10.

The team reviewed the NMPC self-assessment reports and selected questions and responses, including an independent review conducted by a contractor. NMPC's self-assessment covered a scope similar to an NRC EDSFI, and identified 57 open items and 43 observations during the course of the inspection. Based on these open items, NMPC initiated 52 deviation/event reports (DERs). Based on these findings, the team determined that NMPC's self-assessment was comprehensive and of high quality. Three NRC findings were not identified by the NMPC inspection team. These findings are: 1) there was insufficient evidence that the capacity of the day tanks and storage fuel oil tanks met the final safety analysis report (FSAR) commitment; 2) the emergency diesel generators were tested above their two-hour ratings; and 3) lack of an analysis of the impact of the uninterruptible power supplies output voltage total harmonic distortion (THD) in excess of 5% of the fundamental. In addition, there were two significant deficiencies that were also missed by the NMPC self-assessment EDSFI, but were later identified and corrected by NMPC: 1) incorrect tap setting on the 4160-600V transformer which served the HPCS system auxiliaries, and 2) inadequate pickup voltage characteristics of motor starter contactors for the HPCS system motor-operated valves (MOVs). However, the NRC findings and the deficiencies that were identified later by NMPC were, in the team's opinion, a rare exception, rather than a lack of indepth, comprehensive review by the NMPC self-assessment team.

The team selected samples from the EDS in the electrical and mechanical design, and maintenance and test areas for independent review. The scope included a plant walkdown, technical reviews of studies, calculations, design drawings, and station procedures pertaining to the EDS. Interviews were conducted of corporate and plant personnel.

Based on the sample documents reviewed and equipment inspected, the team concluded that the electrical distribution system at Nine Mile Point Unit 2 is capable of performing its intended functions, and that NMPC's actions in response to the deficient condition that the HPCS system injection valve failed to open during testing, were appropriate. However, the team determined that this deficient condition constitutes an apparent violation of Technical Specifications, Section 3.5.1, Item C, as discussed in paragraph 2.9 of this inspection report. The team identified three unresolved items; one in the electrical design area, one in the mechanical design area, and one in the electrical equipment test area.

The inspection findings are summarized as follows:

One Apparent Violation	Discussed In Paragraph	Item Number
HPCS System Inoperable	2.9	EEI93-81-04
Three Unresolved Items		
UPS output voltage THD greater than 5% of the fundamental	2.7	50-410/93-81-01
EDG fuel oil reserve not meeting FSAR commitment	3.2	50-410/93-81-02
EDGs were tested above their two-hour rating	4.2.1	50-410/93-81-03

DETAILS

1.0 INTRODUCTION

During inspections in the past years, the Nuclear Regulatory Commission (NRC) staff observed that, at several operating plants, the functionality of related systems had been compromised by design modifications affecting the electrical distribution system (EDS). The observed design deficiencies were attributed, in part, to improper engineering and technical support. Examples of these deficiencies included: unmonitored and uncontrolled load growth on safety-related buses; inadequate review of design modifications; inadequate design calculations; improper testing of electrical equipment; and use of unqualified commercial grade equipment in safety-related applications.

In view of the above, the NRC developed an electrical distribution system functional inspection (EDSFI) program for operating plants. In response to this, Niagara Mohawk Power Corporation (NMPC) conducted two electrical self-assessments at NMP2 from mid-1991 to October 10, 1993. Their review covered areas similar to an NRC EDSFI. Fifty-seven open items were identified by NMPC. Some of these issues were not yet resolved when this inspection started.

This inspection was conducted to supplement and follow up on NMPC's self-assessment. During this inspection, the NRC team reviewed the NMPC self-assessment report and selected questions and answers from those reviews. In addition, the NRC team also selected areas that they considered important to safety for detailed review, using techniques and past experience developed during previous EDSFIs.

The NRC team's review covered portions of onsite and offsite electrical power sources and included the 115 kV buses, reserve service station transformers, 4.16 kV power system, emergency diesel generators, 600V Class 1E buses and motor control centers, station batteries, battery chargers, 125 Vdc Class 1E buses, uninterruptible power supplies (UPS) and the 120 Vac Class 1E vital distribution system.

The NRC team verified the adequacy of the emergency onsite and offsite sources for the EDS equipment by reviewing regulation of power to essential loads and circuit independence. The team also assessed the adequacy of those mechanical systems that interface with and support the EDS. These included the air start, lube oil, and cooling systems for the emergency diesel generator and the cooling and heating systems for the electrical distribution equipment.

A physical examination of the EDS equipment verified its configuration and ratings and included original installations as well as equipment installed through modifications. In addition, the team reviewed maintenance and surveillance activities for selected EDS components.

In addition to the above, the team verified general conformance with General Design Criteria (GDC) 17 and 18, and appropriate criteria of Appendix B to 10 CFR Part 50. The team also reviewed the plant technical specifications, the Updated Final Safety Analysis Report, and appropriate safety evaluation reports to ensure that technical requirements and licensee's commitments were being met.

This inspection also included a review of NMPC response to the deficient condition that the high pressure core spray system injection valve failed to open during testing as reported in LER 93-10.

The details of specific areas reviewed, the NRC team's findings, and the applicable conclusions are described in Sections 2.0 through 5.0 of this report.

2.0 ELECTRICAL SYSTEMS

The team reviewed the Nine Mile Point Unit 2 (NMP2) electrical distribution system (EDS) self-assessment performed by Niagara Mohawk Power Corporation (NMPC). The scope of this self-assessment was similar to an NRC-performed EDSFI and included the efforts by NMPC and an independent consulting firm, Ogden Environmental and Energy Services. The team noted that several significant issues were identified in the EDS design area:

- Incorrect operational mode for the reserve station service transformer automatic load tap changers;
- inconsistencies, non-conservative considerations and the lack of transient voltage and transient frequency analyses in the emergency diesel generator (EDG) loading studies;
- lack of sizing calculation for the EDG neutral grounding resistors;
- potential for the short circuit current to exceed the 4.16 kV switchgear interrupting capability and the lack of short circuit analysis for the Division III 600V system; and
- incomplete analysis in the degraded grid protection setpoint study regarding the impact of relay tolerances and the operation of low voltage equipment with degraded terminal voltage.

Additional details of this review are discussed, in part, by the following subsections and Section 5.0 of this report.

The team also reviewed a sample of the key features and components of the Class 1E portion of the EDS design and equipment ratings. The review addressed both ac and dc systems and included: a) normal and emergency power sources; b) load analysis and load flow; c) equipment ratings versus worst-case loading; d) voltage regulation; and e) degraded voltage protection.

2.1 Offsite Power and Grid Configuration

The electrical power output of the NMP2 main generator was rated 1348.4 MVA, 0.9 power factor at 25 kV. The generator output voltage was stepped up to 345 kV by a 408 MVA transformer bank located at the station. Connection of this transfer bank to the NMPC grid was made at the Scriba 345/115 kV switchyard which is located approximately 3000 feet from NMP2. In addition to this connection from NMP2, the 345 kV section of the Scriba switchyard also had connections to (a) the NMP1 output, (b) the Fitzpatrick nuclear station output, and (c) the NMPC network via two transmission lines. The 345 kV section of the Scriba switchyard utilized a breaker and a half scheme with two 345-115 kV autotransformers. These two autotransformers were equipped with automatic load tap changers (ALTC) and each served a separate bus in the 115 kV section. These ALTCs were in the auto-mode and the output voltage of each auto transformer was set at 118 kV. The NMP2 electrical distribution system is shown in Attachment 3.

The offsite power supply to the NMP2 was the 115 kV section of the Scriba switchyard. Two separate lines, one from each Scriba 115 kV bus, were routed on separate structures to a three section 115 kV bus located a the NMP2. One line, source A (switchyard line 5) served reserve station service transformer 1A (2RTX-XSRIA) via one bus end section, and the other, source B (switchyard line 6), served reserve station service transformer 1B (2RTX-XSRIB) via the other bus end section. The center bus section served the auxiliary boiler service transformer (2ABS-XI). The 115 kV bus sections were equipped with disconnect switches which were normally positioned to align the center section with source A (line 5); the disconnect between the center section and the section served by source B (line 6) was normally open. Thus, source A normally supplied transformers 2RTX-XRIA and 2ABS-XI while source B normally supplied transformer 2RTX-XRIB. An ALTC was provided for each of the two reserve station service transformers (RSST).

The NMPC self-assessment inspection had observed that the ALTCs for the two RSSTs were being operated in the manual mode. Whereas, it was indicated in Section 8.2.1.4 of NMP2 final safety evaluation report (FSAR) that the ALTCs would be operated in the auto-mode to maintain secondary winding voltage. NMPC documented the concern with deviation/event report (DER) 2-91-Q-0573, dated July 23, 1991. The RSST ALTCs had been in the manual mode since the initial plant startup. NMPC stated that during the preoperation stage, these ALTCs were placed in the manual mode because the upstream 345-115 kV auto transformer ALTC in the Scriba switchyard was being operated in the auto-mode. NMPC performed an operability determination for the ALTC being in the manual mode instead of being in the auto-mode. They determined that there was no operability problem because:

a) The safety equipment was designed for loss-of-offsite-power (LOOP) and degraded voltage conditions;

b) During the LOOP and degraded voltage condition, power would be transferred to the emergency diesel generators;

c) The ALTC being in the manual mode did not affect the undervoltage and degraded voltage settings;

d) NMPC evaluated the over-voltage and determined that the over-voltage would not affect equipment operation. The offsite power voltage was regulated by the Scriba 345-115 kV auto transformers. The voltage level was analyzed by Stone & Webster in their 1985 voltage profile study for different motor loading conditions, with the ALTC being in the manual mode.

NMPC also performed a reportability evaluation and determined that this issue was not reportable because the operability of the safety equipment was not affected.

During the 1992 refueling outage, NMPC changed the ALTC to auto-mode. The timing of the Scriba 345-115 kV transformers was changed from 60 seconds to 30 seconds, and the RSST ALTC timing was set at 60 seconds. These settings were selected to avoid voltage oscillation during large motor starting. NMP2 Operation Procedure NZ-OP-72 was revised to incorporate these changes. NMPC also completed a 50.59 evaluation and determined that there were no unreviewed safety questions for the above changes. The RSST ALTCs have been in the auto-mode since the startup from the 1992 refueling outage.

The team concluded that the actions taken by NMPC in response to the DER were appropriate.

The team observed that during the recent refueling outage NMP2 experienced a partial loss of offsite power. Specifically, the source A, which supplies Division I equipment, was lost while the plant was in the refueling mode. Source B was unaffected. This event was reported to the NRC by licensee event reports (LER) 93-08, dated December 1, 1993, titled "Engineered Safety Feature Actuations Due to a Partial Loss of Offsite Power Caused by a Personnel Error," and LER 93-09, dated December 2, 1993, titled "Engineered Safety Feature Actuations Resulting From a Loss of Power to RPS and RCIS Caused by Personnel Error." The team found no design concerns associated with these two LERs and that further analysis of these LERs was outside of the scope of the EDSFI.

The team observed that the 115 kV offsite power source had been the subject of an earlier NRC inspection on July 19-23, 1993. At that time the inspector concluded that the 115 kV offsite power source was reasonably reliable. The inspection findings were discussed in the combined inspection report 50-220/93-15 and 50-410/93-15. The EDSFI team's review of the 115 kV power source did not identify any concerns that would change the previous assessment.

2.2 Bus Alignment During Startup, Normal Power and Shutdown Operations

The medium voltage portion of the EDS consisted of the following:

- two nonsafety-related 13.8 kV buses for normal unit auxiliaries (2NPS-SWG001 and 2NPS-SWG003);
- one nonsafety-related 13.8 kV bus for the auxiliary boiler auxiliaries (2NPS-SWG002);
- five nonsafety-related 4.16 kV buses for the normal unit auxiliaries (2NPS-SWG011 through SWG015) and
- three safety-related 4.16 kV buses, one each associated with engineering safeguards Division I (2ENS*SWG101), Division II (2ENS*SWG103) and Division III (2ENS*SWG102).

During unit startup and shutdown, half of the unit normal auxiliary buses were served by reserve transformer 2RTX-XRIA; the other half of the auxiliary buses were served by reserve transformer 2RTX-XRIB. The auxiliary boiler bus was served by transformer 2ABS-XI. The Division I and Division III buses were served exclusively by a tertiary winding of reserve transformer 2RTX-XRIA and the Division II bus was served exclusively by a tertiary winding on reserve transformer 2RTX-XRIB. However, in the event either reserve station service transformer was temporarily out of service, the associated Division I or Division II bus could be served by a 4.16 kV tertiary winding of the auxiliary boiler service transformer.

Following startup, the units normal auxiliary buses were manually transferred to the normal station service transformer 2STX-XNS1 which was connected to the unit main generator leads.

2.3 Bus Transfer Schemes

The team observed that following a unit trip, the normal auxiliary buses were transferred from the normal station service transformer to the reserve station service transformers by an automatically initiated fast dead-bus transfer scheme. Since the Division I, II and III buses remained connected to the reserve transformers during normal operation, no transfer was required for these buses following a unit trip.

The team observed in the NMPC self-assessment that the impact of the above fast dead-bus transfer on the safety-related Division I, II and III buses had been addressed. NMPC had analyzed the transfer and concluded that the scheme was acceptable. The team did not review the analysis.

2.4 Class 1E AC Power Systems

The team observed that the Class 1E ac power systems included a 4.16 kV system and a 600V system. The 4.16 kV Class 1E systems consisted of three separate and independent buses for Division I, II and III. Division I and Division III were served by offsite source A while Division II was served by offsite source B. Each division had a standby emergency supply from its own dedicated emergency diesel generator. Division I and Division II systems were essentially redundant and served load center transformers and pump drive motors associated with the low pressure core spray system, service water system, residual heat removal system and the spent fuel pool cooling system. Division III served the high pressure core spray system pump drive motor and a motor control center.

The 600V Class 1E systems included three separate and independent sets of load center switchgear and motor control centers. Division I and Division II load centers were each double-ended, i.e., had the capability of being served by one of two 4.16 kV-600V transformers. These load centers served the larger low voltage motors (150 HP and larger), larger low voltage non-motor loads (60 kW and larger) and motor control centers. The Division III 600V system had a single 4.16 kV-600V transformer which served the division's motor control center. Division III had no load center switchgear.

The team noted that the NMPC self-assessment had implied that all 4.16 kV-600V transformers were provided with appropriately rated surge arresters. However, in response to the team's query, NMPC advised that, in fact, the Division III 4.16 kV-600V transformer was not provided with surge arresters. Further, in response to the team's concern NMPC performed an evaluation which concluded that the basic impulse level (BIL) provided for the transformer insulation would withstand the potential surges on the 4.16 kV system to which it could be exposed.

The team reviewed the electrical distribution equipment loadings for the Class 1E ac electrical distribution system equipment based on the NMPC calculation EC-151, Revision 0, dated November 13, 1992, titled "Auxiliary System Performance Using ELMS-AC," including the calculation dispositions 00A, 00B and 00C, dated January 7, 1993, May 4, 1993, and May 6, 1993, respectively. This documentation indicated that, under worst-case loss of reactor coolant (LOCA) conditions, the reserve station service transformers, 4.16 kV switchgear, 4.16 kV-600V transformers, 600V switchgear and 600V motor control centers would be operated within their designed ratings.

In their self-assessment, NMPC had identified a concern with the potential fault duty to which the 4.16 kV switchgear could be exposed while testing either the Division I or Division II EDG in parallel with the 115 kV system through the auxiliary boiler service transformer. NMPC addressed this concern in DER 2-92-3960, dated November 3, 1992. Resolution involved a rerun of the ELMS-AC program for calculation EC-151 using a more

realistic short circuit time constant for the emergency diesel generator. The self-assessment also identified a lack of a short circuit analysis for the Division III 600V system. This concern was addressed by NMPC in their DER 2-92-Q-1788, dated April 21, 1992. Resolution involved the generation of calculation EC-151, Revision 0, which indicated acceptable fault levels on Division III 600V system.

Based on the team's review of the referenced deviation/event reports and calculation EC-151, the team concluded that the loading and potential fault duties were within the Class 1E ac power system equipment capabilities.

2.5 Emergency Diesel Generator

The team observed that a dedicated emergency diesel generator (EDG) is provided for each Class 1E ac power system. The ratings of the EDGs are as follows:

	Division I & II	Division III
8760 hour (continuous) rating	4400 kW	2600 kW
2000 hour (short time) rating	4750 kW	2850 kW
2 hour rating	4840 kW	2860 kW

NMPC identified, during their self-assessment, that their calculation EC-032, Revision 7, titled "Diesel Generator Loading," which was used to document the worst-case loading, contained inconsistencies. Namely, the calculation did not consider cable losses nor actual motor power factors. Further, the calculation did not address the transient voltage and frequency conditions encountered during the EDG loading sequences. To address these concerns, NMPC issued DER 2-92-Q-1782, dated April 2, 1992, and DER 2-92-3628, dated October 6, 1992. In addition, NMPC determined that a scenario of a loss-of-offsite power (LOOP) followed by a LOCA had not been analyzed. To address these concerns, NMPC issued DER 2-92-Q-1461, dated April 7, 1992. Resolution of the steady-state loading concerns involved revising calculation EC-32 as Revision 8, dated January 4, 1993, which did consider transformer and cable losses and, where known, actual motor brake horsepower and power factor (otherwise nameplate horsepower and power factor). This revision of the calculation, based on the "ELMS-AC" program used in calculation EC-151, Revision 0, determined the worst-case loading on Divisions I, II and III EDGs to be 4292 kW, 3875 kW and 2540 kW, respectively, which is within the EDG continuous rating.

The resolution of the transient voltage and frequency concern involved the issuance of a new calculation, EC-156, Revision 0, dated June 29, 1993, entitled "Diesel Generator Transient Analysis," which was based on the electrical transient analyzer program "ETAP." The team noted from the results of this calculation that, for Division I and Division II, generator output frequency did not recover to 98 percent as implied by the calculation objective, and the regulatory position given in USNRC Regulatory Guide 1.9, Revision 3, dated July 1993. In response to the team's concern, NMPC made a preliminary rerun of the "ETAP" program using the known brake horsepower for motor loads when known rather than the rated

horsepower. In addition, the EDG governor and exciter transfer function constants were changed to better represent the NMP2 EDG units. The rerun of the program yielded an acceptable frequency recovery. NMPC advised that the next revision of calculation EC-156 will be issued using this more realistic data.

In their self-assessment inspection, NMPC also identified the lack of a EDG generator neutral grounding resistor calculation. This was addressed by DER 2-92-Q-1256, dated March 31, 1992. The concern was resolved by the issuance of calculation EC-153, which addressed the EDG generator neutral ground resistor, Revision 0, dated September 30, 1992.

Based on review of the referenced DERs and calculations EC-032 and EC-156, the team concluded that the loadings on the EDGs were within their designed capabilities.

2.6 Degraded Voltage Protection Schemes for Class 1E Buses

2.6.1 First Level Voltage Protection

The team observed that the setting of the first level, or loss of voltage, protection scheme for the Class 1E 4.16 kV buses was 3212 volts or about 77 percent of nominal. Three relays were provided for this function on each bus; i.e., one per phase, and acted in two-out-of-three logic to detect loss of the offsite power supply to the associated bus. Following a time delay of about 3 seconds, load shedding and EDG starting for that bus would have been initiated. The team did not identify any concerns in the review of this protection scheme.

2.6.2 Second Level Voltage Protection

The team observed that the setting of the second level, or degraded voltage protection scheme for the Class 1E 4.16 kV buses was 3847 volts, or about 92.5 percent of nominal. NMPC determined that with this setting, when considering relay tolerances, the protection scheme actuation could occur at 3770 volts or 90.6 percent of nominal. NMPC had determined, using their preliminary revision 4 to calculation EC-136, titled "Degraded Voltage Relay Set Point," that the lower limit of the setting, i.e., 3770 volts, would still provide sufficient voltages for the 600 volt safety-related motors (at least 90 percent of nameplate rating for running conditions and at least 80 percent of nameplate rating for motor starting). The preliminary revision of calculation EC-136 was based on the "ELMS-AC" program used in calculation EC-151, Revision 0.

The team noted that, as was the case for the first level protection, three relays were provided on each bus, i.e., one per phase, and acted in two-out-of-three logic to detect unacceptable degraded voltage conditions on the associated bus. This scheme had two time delays. The first time delay was set at 8 seconds and acted in the event of a LOCA; the second time delay was set at 30 seconds without a LOCA. Following either time delay actuation, bus stripping and EDG starting is to be initiated for the associated bus.

The team did not identify any concerns with the design of this second level voltage protection scheme.

2.7 Class 1E 120 VAC System

The team noted that the Class 1E 120 Vac system consisted of two uninterruptible power supplies (UPS) which served the plants instrumentation and controls associated with the emergency core cooling system. These UPS systems each had a rated output of 25 kVA at 120 volts, plus or minus 2 percent and 60 hertz, plus or minus 0.5 hertz. The team noted that for the kVA loading, these UPS systems were well within their capabilities.

Both the NMP2 FSAR and the UPS procurement specification identified the total harmonic distortion (THD) of the output voltage to be not more than 5% of the fundamental. It was not clear to the team nor NMPC engineers whether the 5% applied to the loaded or unloaded conditions. Tests conducted by NMP2 plant personnel indicated that during the unloaded condition, the THD was 3.9%, while during the loaded condition, the maximum THD was 9%. In response to the team's concern, NMPC performed a thorough analysis, which indicated that all loads connected to the UPS were determined to be operable because many of these loads were immune to a higher THD. Subsequently, NMPC issued DER 2-93-2905, entitled, "UPS with a THD Greater Than 5%," on December 15, 1993, to address this issue. This DER requires further analysis to determine the acceptance criteria for the THD and to establish control of future load addition. This item is unresolved pending NRC review of the resolution of DER 2-93-2905 (50-410/93-81-01).

2.8 Class 1E 125 VDC Systems

The team observed that the Class 1E 125 vdc systems consisted of three separate systems; one each for Division I, II and III. The Division I and Division II systems each consisted of a 2550 AH (8 hour rate), 60 cell, calcium grid, lead acid battery bank, two 300 A chargers and associated panelboards. The Division III system consisted of a 100 AH (8 hour rate), 60 cell, calcium grid, lead acid battery bank, two 50 A chargers and associated panelboards. The second charger of each system was an installed spare which could be manually placed in service when required.

The NMPC self-assessment inspection identified two technical specifications concerns involving these systems. The first related to electrolyte temperature. Both the FSAR, Section 8.3.2.1.2, and design calculations considered 65° F to be the minimum electrolyte temperature whereas Technical Specification 4.8.2 specifies a surveillance requirement for a minimum temperature of 60° F. NMPC has requested, by a letter to the NRC, dated December 14, 1993, that the Technical Specification be changed to 65° F.

The second NMPC-identified concern involved Division I and Division II systems. Technical Specification Section 3.8.2.2 requires that both the primary and backup chargers be in operation when the associated UPS system is powered by its backup dc supply. NMPC determined that, if the battery had been discharged prior to the connection of the second charger, there was a potential for the bus supply breaker to trip when both chargers went to their current limit. NMPC verified the adequacy of one charger to supply the normal dc loads, including the dc requirements of the UPS, and recharge the battery within 24 hours. As a result, NMPC has requested, by the same letter as above, that the Technical Specification be changed to delete the requirement for the operation of the second charger.

NMPC identified a few minor concerns involving assumptions used in the 125 Vdc system calculations including battery design margin, battery temperature correction factor and loading assumptions. These concerns where addressed and resolved by the deviation/event report process. The team did not identify any additional concerns with the Class 1E 125 Vdc system design.

2.9 Class 1E AC Power System Equipment

The team reviewed NMPC licensee event report (LER) 93-10, dated December 8, 1993, regarding the inoperability of the High Pressure Core Spray (HPCS, Division III emergency core cooling) system due to equipment deficiencies. The LER reported a failure to operate the HPCS system injection valve motor starter opening contactor during a test that was performed on November 8, 1993, during the 1993 refueling outage. The opening contactor, located in motor control center 2EHS*MCC201, provides electrical power to the valve motor to open the valve when that contactor picked up. NMPC determined that the control voltage applied to the contactor was insufficient for the starter coil to pickup, thus preventing the HPCS system injection valve (2CSH*MOV107) from opening. NMPC stated that the design specifications had required the contactor to operate with 96 volts (80 percent of 120 volts) or less across the contactor coil.

NMPC determined that the inadequate coil voltage was due to two separate conditions. One of these conditions was that the tap setting on the 4160-600V transformer (2EJS*X2) was set at +2.5% rather than -2.5% as specified in the design. This resulted in a 5% voltage reduction on the 600V motor control center bus. The second condition was the inability of the valve motor starter coil (GE size 2 contactor) to pickup at 96 volts (80% of the coil rating) as determined by testing. Both conditions existed in the plant since initial startup more than five years ago. Further, NMPC determined that either condition alone would have prevented valve actuation during degraded voltage conditions. This problem was not detected and corrected earlier because it was obscured by the ALTCs for the RSSTs being operated in the manual mode as discussed in Section 2.1. When the ALTCs were in the manual mode, the 4.16 kV bus voltage was increased about 2.6%, resulting higher control voltage across the valve motor starter coil. NMPC made these ALTC features operational and set at auto-mode before startup from the 1992 refueling outage. The 4160V bus voltage was maintained at nominal voltage since then.

NMPC stated that the HPCS system injection valve passed all tests conducted prior to the 1993 refueling outage.

During the 1993 refueling outage, several tests were conducted for this valve. The first test was a static test (stroking the valve with the HPCS pump stopped) that was conducted on October 4, 1993, and passed. The second test was a dynamic test (with the HPCS pump running) and was conducted on October 5, 1993. The valve opened successfully. The third test was also a dynamic test conducted on November 8, 1993. The valve failed to open. Subsequently, DER 2-93-2622 was generated and the valve was declared inoperable (LER 93-10 was issued later). On November 10, 1993, after cleaning various contacts in the control circuit, NMPC stroked the valve twice (HPCS pump not running), and the valve opened successfully. On November 15, 1993, NMPC attempted to stroke the valve, and the motor contractor failed to pick up. All of the above tests were conducted before the deficiencies were corrected, which took place between November 17, 1993, and November 21, 1993. The offsite power supply was at normal voltage during the above tests. However, specific voltages were not measured in each case. After the motor contactor was replaced and the transformer tap setting corrected, a dynamic test was conducted on November 21, 1993, and passed.

During this inspection, NMPC performed a preliminary calculation, which indicated that, before the deficiencies were corrected, and with the 4160V bus being at nominal voltage, the valve motor control circuit had barely enough voltage for the contactor coil to pick up, with no margin.

The corrective actions taken and completed by NMPC included:

a) Replaced four GE size 2 contactors in the HPCS 600V motor control center with Gould contactors, which have a pull-in voltage of 86V or less, and corrected the transformer tap setting from +2.5% to -2.5%.

b) Verified, by measuring the secondary voltage, that the Divisions I and II switchgear transformer taps were set correctly.

c) Reviewed the preoperation test data for Divisions I & II contactors and determined that the contactors could pull in under degraded voltage conditions. It was found that Divisions I and II switchgear use Gould contactors. This type of contactor has a pull-in voltage of 86V or less.

The above corrective actions were verified by the team during the inspection.

For the contactors in the HPCS 600V motor control center that were not replaced, NMPC provided the following justifications:

a) Two GE size 2 contactors were not replaced because they were used for equipment which is required to function only when the HPCS pump was in the standby mode and was not required to function during an accident. In addition, the test data indicated that these two contactors required pull-in voltage of 89V or less.

b) GE size 1 and size 3 contactors were not replaced because the test data indicated that these contacts would pull-in with less than 96 V.

The team considered this justification to be appropriate.

NMPC determined the root cause for the valve motor contactor deficiency to be an equipment deficiency that was not identified during plant startup testing due to inadequate methods used to evaluate startup test data. NMPC also determined the root cause of the incorrect transformer tap setting to be poor work practices during plant construction and preoperational testing. The team reviewed NMPC's program for plant modification to ascertain whether their current practices would preclude the above deficiencies. For a typical plant modification, the project engineer interfaces directly with the design engineers and procurement engineers to assure that the design requirements are properly incorporated into the purchasing requirements. Upon receipt of the procured items, receipt inspection and document reviews are performed by the procurement engineers to ensure conformance with the design requirements. Post-modification tests are required to demonstrate proper operation of the equipment. Any nonconformances identified are documented in a DER and resolved through the DER program. During this inspection, the team interviewed project engineers, procurement engineers, design engineers, QA engineers, and testing personnel. The team found them knowledgeable and familiar with the program procedures. Within the scope of this review, the team did not find a current problem with the programs that led to the motor contactor deficiency.

The team determined that the HPCS system injection valve would not open during degraded voltage conditions, which rendered the HPCS system inoperable from initial startup of the plant until the deficiencies were corrected in November 1993. This deficient condition constitutes an apparent violation of NMP2 Technical Specifications, Section 3.5.1, item C, which requires that the HPCS system be operable during conditions 1, 2, and 3 (EEI 50-410/93-81-04).

2.10 Conclusion

The team concluded that the ac and dc systems were generally well designed and conformed to the Technical Specifications and NMP2 FSAR with the exception of the two items (battery minimum electrolyte temperature and the battery backup charger) for which NMPC has requested Technical Specification revisions (discussed in Section 2.8). The team also concluded that the EDS components were adequately sized and configured, and that the actions taken by NMPC in response to the HPCS system injection valve issue were

appropriate. One apparent violation (identified by NMPC) and one unresolved item were identified in this area. The apparent violation pertains to the inoperability of the HPCS system, while the unresolved item pertains to the total harmonic distortion of the UPS output voltage.

3.0 MECHANICAL SYSTEMS

To verify the loading on the emergency diesel generators, the team reviewed the power demands of major loads for selected pumps and the translation of mechanical into electrical loads as input into the design basis calculations. The team also conducted a walkdown of the supporting mechanical systems, including the diesel generator cooling water system, the starting air system, the lube oil system, and the heating, ventilation and air conditioning (HVAC) systems for the emergency diesel generators (EDG) rooms, the ac and dc switchgear areas and battery rooms.

3.1 Power Demands for Major Loads

The team reviewed the power demands for the major pump motors on the EDGs following a loss of coolant accident (LOCA) plus a loss of offsite power (LOOP) condition. Other combination of LOCA and LOOP conditions discussed in the Nine Mile Point 2 (NMP 2) Updated Safety Analysis Report (USAR) were also reviewed. This review was based on the information provided in the NMPC self-assessment report and review of the design calculations, procedures and memoranda. The majority of the break horse power (BHP) curves, for the large pumps, exhibited peak values. For these pumps, maximum BHP values were conservatively assumed to be in excess of the peak values indicated on the BHP vendor certified curves. For the pumps which had an increasing BHP characteristic (e.g., service water pump) NMPC used very conservative assumptions to maximize the flow rates. These flow rates were utilized to determine the corresponding BHP values for input into the EDG loading calculation. Based on this review, the team has determined that the power demands for the major pump motors on the EDG were conservatively established in the Diesel Generator Loading Calculation No. EC-32, Rev. 8.

The team also reviewed a resolution of a concern related to a potential for EDG overloading due to a lack of the administrative controls in the operating procedures, which was identified during the NMPC's self-assessment. The existing procedures did not restrict the restart of the tripped low pressure core spray or residual heat removal pump motor during a LOCA/LOOP condition with a nearly fully loaded diesel. The team found the NMPC's corrective actions (a revision of the appropriate procedures) undertaken to resolve this concern, to be appropriate.

3.2 Diesel Generator and Auxiliary Systems

The team reviewed the NMPC's calculations, procedures, and drawings to determine the design adequacy of the diesel generators and auxiliary systems. A summary of the team's findings is given below.

NMP 2 has three EDGs. Two EDGs are rated at 4,400 kW each and supply power to Divisions I and II emergency loads. The third EDG is rated at 2,600 kW and is supplying power to high pressure core spray (HPCS - Division III) system. Each EDG has its own day tank and (7 day) storage tank. Two fuel oil transfer pumps per EDG are used to transfer fuel oil to day tank from its respective storage tank.

The FSAR, Section 9.5.4.2.1, stated that each storage tank (approximately 52,664 gal. for each of the standby diesel generator fuel oil storage tanks, and 36,173 gal. for the HPCS diesel generator fuel oil storage tank) is sized to store sufficient oil for continuous operation of its respective diesel engine at rated capacity for 7 days. The FSAR, Section 9.5.4.2.3, stated that based on a fuel consumption of 5.472 gpm at a rated 4,480 kW for the Division I and II diesels, and 3.361 gpm at a rated 2,850 kW for the Division III diesel, the 1-hr running time volumes, including the dead volume in the tanks are 409 gal and 282 gal, respectively. To verify these commitments the team reviewed nine related mechanical and electrical calculations.

The team's review of these documents generated some concerns related to the NMPC's ability to meet its FSAR commitments. The discussion presented below provides basis for the team's concerns and the NMPC's response.

a) The fuel oil consumption rate changes and the variation in the fuel oil properties were not considered in the above calculations. The committed fuel oil tank (both day and storage) capacities were established based on the results of the EDG tests for the Division I & II diesels and on a vendor manual data for the HPCS diesel. The team expressed concern with using the data as a basis for the tank volume calculation without addition of any margin to allow for changes in the diesel conditions and/or acceptable variation of the fuel properties. This is especially true for the HPCS diesel, since the calculation was based on a typical consumption rate. NMPC concurred with the team's concerns and performed a preliminary engineering evaluation of the impact of these assumptions. This evaluation indicated a potential for a small shortfall (within a couple of percentage points) from the committed volumes. However, at this time, the team could not make a final determination regarding the NMPC's compliance with the FSAR commitments, since NMPC did not have vendor's input required to complete the evaluation.

b) The effects of the temperature changes were not considered in the above calculations. The fuel oil tank capacities were established based on constant fuel oil temperature. Although this assumption is true for the underground storage tanks, it is not always true for the day tanks. The day tanks are located in their respective EDG rooms and see wide temperature variations. This is further compounded by the use of volume-based instruments for tank level monitoring. (Unlike a differential pressure type, this type indicates level based on a constant volume and not constant mass. The vendor consumption rates are mass-based.) NMPC concurred with the team's concerns and evaluated its impact as part of the preliminary engineering evaluation discussed in item a) above. Pending completion of this evaluation, the team deferred its assessment of the impact of the temperature changes on the FSAR commitments.

This is an unresolved item pending NRC's review of the completed evaluations discussed in items a) and b) above (50-410/93-81-02).

The team reviewed issues related to the EDG cooling identified in the self-assessment. The team agreed with NMPC's conclusion that the safety-related service water (SW) system provides adequate cooling to the EDGs.

The team noted that the process safety limits, established in mechanical set point calculations, were incorrectly incorporated into electrical calculations. The error in the incorporation of the process safety limits was originally discovered by NMPC during the self-assessment. The team agrees with NMPC's assessment that this error did not affect Technical Specification limits. NMPC reconciled all of the affected calculations prior to completion of this inspection. However, this error appears to be a part of the wider set point programmatic issue, which has been recognized by NMPC. The set point issue is tracked (internally) by NMPC. The NMPC's resolution of this issue encompasses a variety of far reaching and broad corrective actions which are scheduled for completion by December 31, 1995. In the interim, NMPC assessed the accuracy of the NMP2 set point calculations for NSSS (nuclear steam supply system) and BOP (balance of plant) positions of the Technical Specifications for reactor protection. The preliminary results of this review indicate that these calculations will not require any changes.

3.3 Heating, Ventilation, and Air Conditioning (HVAC) Systems

The team reviewed the design of the HVAC systems which provide services to the electrical equipment within the scope of the EDSFI review, namely: Division I, II & III battery rooms, switchgear rooms, diesel generator rooms, and diesel generator control rooms. The documents used for this review were the NMPC's calculations, procedures, drawings, and the findings of the self-assessment.

The team reviewed related issues identified in the self-assessment. These issues were: 1) the EDS equipment cooling; 2) hydrogen concentration; and 3) EDG room exhaust fan protection. The team concurred with the NMPC's resolutions of these issues, which were as follows: 1) the safety-related SW system provides adequate cooling of the EDS equipment; 2) the design of the HVAC system provides adequate hydrogen removal and complies with the FSAR, Section 9.4.1.2.4, commitment that each battery room is maintained at a negative pressure with regard to the surrounding areas; and 3) the set point for the EDG room exhaust fan low flow condition will provide an adequate protection to the exhaust fan operation. Additionally, NMPC had verified operation of tornado dampers during this inspection.

The team also reviewed issues related to tornado and missile protection of the HVAC systems and found that the afforded means of protection were adequate.

3.4 Conclusions

The team, based on the review of the design attributes within the scope of this inspection, concluded that the mechanical systems supporting the EDG and other electrical equipment are capable of performing their design functions. The team also observed that the mechanical systems, within the scope of this inspection, had ample margin based on generally conservative design. One unresolved item was identified: there was no evidence that the capacity of the day tank and the fuel storage tank meets the FSAR commitments.

4.0 ELECTRICAL DISTRIBUTION SYSTEM EQUIPMENT

The scope of this inspection element was to assess effectiveness of the controls established to ensure that the design bases for the electrical system was properly tested and maintained. This effort was accomplished through the review of the results of the NMPC's self-assessment, field walkdown and verification of the as-built configuration of electrical equipment as specified in the electrical single-line diagrams, modification packages, and site procedures. In addition, the maintenance and test programs developed for electrical system components were also reviewed to determine their technical adequacy.

4.1 Equipment Walkdowns

The team inspected various areas of the plant to verify the as-built configuration of the installed equipment. Areas inspected included the EDGs, EDG control rooms, 4 kV switchgears, batteries, inverters, and 480V load centers. Class 1E transformers were also examined.

The walkdown indicated that adequate measures were in place to control system configuration. All electrical equipment was found to be generally well maintained with surrounding areas clear of the safety hazards. In general, the electrical equipment installed adhered to the design requirements.

The team reviewed issues identified in the self-assessment related to housekeeping and potential safety hazards. During the walkdown, the team observed that all housekeeping potential safety hazard issues were satisfactory resolved. The general plant condition gave the impression of good housekeeping practices, especially considering that the unit was being returned to service after an outage at the time of the walkdown.

4.2 Electrical Equipment Maintenance and Testing

The team reviewed the results of the NMPC's self-assessment, various maintenance and testing procedures for equipment such as the emergency diesel generator, batteries, battery chargers, 4 kV switchgear, molded case circuit breakers, and protective relays. NMPC personnel were interviewed to assess their understanding of the testing and maintenance programs. The team observations are described below.

4.2.1 Emergency Diesel Generator Testing

Periodic surveillance testing of the EDGs was conducted to assure their operational availability and capacity to perform their shutdown functions. The Technical Specifications (TS) for NMP2, Section 4.8.1.1.2, provided monthly and 18-month test requirements for each EDG to demonstrate operational readiness. These requirements were implemented by the monthly surveillance tests and by the 18-month endurance tests.

The team reviewed monthly surveillance test procedures and 18-month test procedures and several completed monthly and 18-month records test. The team concluded that the test procedures included adequate acceptance criteria that were consistent with the TS requirements. Review of completed test records indicated that the tests were conducted in accordance with the test procedures.

The 18-month test procedure specified an EDG load equal to or greater than its 2 hour rating of 4840 kW (Division I & II EDGs) and 2860 kW (Division III EDG) for the first 2 hours without specifying the upper limit. During the remaining 22 hours, this test procedure specified an EDG load equal to or greater than its continues rating (also without the upper limit value) of 4400 kW (Division I & II EDGs) and 2600 kW (Division III EDG). The team reviewed the test data of past two 18-month tests for all three EDGs.

The test data indicated the following: 1) Division I & II EDGs were loaded consistently between 4850 and 4910 kW for first 2 hours and between 4400 and 4500 kW for the remaining 22 hours in each test; and 2) Division III EDG was loaded consistently between 2900 and 2910 kW for first 2 hours and between 2600 and 2700 kW for the remaining 22 hours in each test.

NMPC's position on this issue was as follows: 1) the temperature and other variables observed during these tests were well within the normal operating range; and 2) the maintenance inspections, which took place 18 months after each endurance test, did not reveal any unexpected wear to the diesel engine parts that would be expected to indicate wear. Additionally, NMPC contacted both EDG vendors concerning the consequences of these tests. The vendors' responses indicated that testing with slightly above rated load would not damage the EDGs. Also, NMPC revised appropriate procedures by addition of caution statements which identified maximum load not to be exceeded.

The team agreed with NMPC that the current condition does not present an immediate operability concern. The long term concern, associated with the continuing operation of the diesels above their rating, requires further resolution. Pending NRC's review of the provided information and/or corrective actions by NMPC, this item is unresolved (50-410/93-81-03).

The team also reviewed issues related to a potential for fuel exposure below the cloud point (formation of paraffin due to a low temperature exposure) before the fuel was transferred to the storage tank from the delivery truck, identified in the self-assessment. NMPC has an operation procedure in place which requires the delivery truck to be stored in a heated enclosure during the winter. The team agreed with the NMPC's conclusion, that this operation procedure provided an adequate protection against fuel exposure below cloud point.

4.2.2 Station Batteries

The team reviewed the testing program of the station batteries to assure that adequate dc power was available to operate the dc equipment. There were three 125 Vdc batteries - one for each division. The team reviewed 18-month and 60-month test procedures and their test results to assure that they meet the surveillance requirements stated in the TS, Section 4.8.2.1. The team noted that the test procedures included adequate acceptance criteria that were consistent with the TS requirements. Review of completed test records indicated that these tests were conducted in accordance with the test procedures. The team concluded that the 18-month and 60-month tests for 125 Vdc batteries at NMP 2 were properly implemented.

The team reviewed related issues identified in the self-assessment. These issues were as follows: 1) the battery charger output voltage regulation commitment; and 2) electrolyte minimum temperature requirements of 60°F vs. 65°F. NMPC's resolutions of these issues were as follows: 1) NMPC contacted the battery charger vendor and obtained the results of the original charger test, which confirmed the voltage regulation commitment; and 2) NMPC had submitted a TS change request, requesting changing the minimum temperature in TS 4.8.2.1.b.3 from 60°F to a more conservative value of 65°F (this issue was also discussed in paragraph 2.8 of this report).

4.2.3 Relay Testing

The team reviewed the NMPC calibration and testing program for protective relays used in the safety-related portions of the EDS. The team noted in the procedures that safety-related relays, such as loss of voltage and degraded voltage relays, reactor coolant pump drive motor overcurrent relays and safety-related pump drive motor auto start time delay relays are calibrated and tested every 18 months to conform with the technical specifications. Other safety-related protective relays are calibrated and tested on a less frequent schedule of either every 30 months or 42 months depending on relay model and style number. Auxiliary relays are tested every 6 years. The team did not identify any concerns with the program.

4.3 Conclusions

Based on the review of the documents, the team concluded that NMPC had an acceptable maintenance and testing program for the electrical distribution system equipment at NMP 2. One unresolved items was identified in these areas: the EDGs were tested at a power output greater than the 2 hour rating of 4840 kW (Division I & II EDGs) and 2860 kW (Division III EDG).

5.0 REVIEW OF NMPC's SELF-ASSESSMENT OF THE ELECTRICAL DISTRIBUTION SYSTEM

The team reviewed the NMPC's self-assessment report and selected questions to determine the adequacy of their review. The self-assessment was performed by NMPC from mid 1991, to October 10, 1993. In addition, NMPC contracted with Ogden Environmental and Energy Services (Ogden) to perform an independent review. The Ogden team consisted of six team members: one team leader, two electrical design reviewers, two mechanical design reviewers, and one operations and testing reviewer.

The NMPC's self-assessment covered electrical system design, mechanical system design, electrical equipment testing and maintenance, and engineering and technical support (E&TS) areas. The electrical system design covered offsite and onsite systems, including offsite grid stability, bus alignments, voltage studies, emergency diesel generator (EDG) load calculations, and station batteries and battery chargers. The mechanical system design covered EDG auxiliary systems (fuel oil, cooling water, lubrication oil, and starting air systems), HVAC for switchgear room, EDG rooms, and battery rooms. It also covered service water system performance in support of the EDS equipment, tornado and missile protection, and hydrogen accumulation in the battery rooms. The electrical equipment testing and maintenance included maintenance and testing of EDGs, protective relays, circuit breakers and fuses, batteries and battery chargers.

The NMPC's self-assessment team identified 57 open items and 43 observations. Based on these findings, 52 deviation event reports (DERs) were generated. Out of these 52 DERs, 44 were closed and the required corrective actions implemented by NMPC prior to completion of the NRC inspection. The team was impressed not just by the number of questions, but also by their quality and depth. The team concluded that the self-assessment findings had been appropriately reviewed and prioritized by the NMPC.

Based on this review, the team concluded that the NMPC's self-assessment was comprehensive. It covered sufficient areas for a normal EDSFI. The number and significance of their findings indicated an excellent level of detailed review. Examples of significant findings are: 1) incorrect operational mode for the reserve station service transformers' automatic load tap changers as discussed in Section 2.1, and 2) non-conservative considerations and the lack of transient voltage and transient frequency analyses in the emergency diesel generator loading studies as discussed in Section 2.5. Certain issues were not identified. These included: 1) there was insufficient evidence that the capacity of the day tanks and storage fuel oil tanks met the final safety analysis report commitment; 2) the emergency diesel generators were tested with power output greater than their two-hour rating; and 3) lack of an analysis of the impact of the uninterruptible power supplies output voltage total harmonic distortion (THD) in excess of 5% of the fundamental. In addition, there were two significant deficiencies that were also missed by the NMPC self-assessment, but were later identified and corrected by NMPC: 1) incorrect tap setting on the 4160-600V transformer which served the HPCS system auxiliaries; and 2) inadequate pickup voltage characteristics of motor starter contactors for the HPCS system motor-operated valves (MOVs). However, these additional findings and the deficiencies that were identified later were, in the team's opinion, a rare exception, rather than the lack of indepth and comprehensive review by the NMPC self-assessment team.

6.0 UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, deviations, or violations. Unresolved items are identified in the Executive Summary of this report.

7.0 EXIT MEETING

The licensee's management was informed of the scope and purpose of this inspection at the entrance meeting on November 29, 1993. The findings of this inspection were discussed with the licensee's representatives during the course of the inspection and presented to licensee management during the exit meetings on December 17, 1993, and January 28, 1994. The licensee did not dispute the inspection findings during the exit meeting. A list of attendees is presented in Attachment 1.

ATTACHMENT 1

Persons Contacted

Niagara Mohawk Power Corporation

T. Aiken	Electrical Engineer, Unit 2 Design
A. Anderson	Operations Department Specialist
W. Baker	Licensing Program Director
M. Bullis	Supervisor, Administrative Service
U. Buiva	Lead Engineer, Electrical Design
J. Bunyan	Senior Project Engineer
J. Conway	Acting Plant Manager, Unit 2
R. Dean	Manager, Technical Support, Unit 2
C. Deban	Manager, Information Management
R. Deuvall	Supervisor, Mechanical Design
S. Doty	General Supervisor, Electrical Maintenance
G. Eldridge	EQ Program Manager
P. Flint	Steno., Administrative Service
D. Greene	Manager, Licensing
J. Guariglia	Specialist, Mechanical Maintenance
J. Halusic	Lead Engineer, Mechanical Design
A. Issa	SQ Program Manager
J. Jirusek	Lead Engineer, Special Programs
A. Julka	Supervisor, Unit 2 Electrical Engineering
N. Kabarwal	Lead Electrical Design Engineer
K. Korcz	Licensing, Unit 2
H. Lockwood	Supervisor, Relay and Control
R. Main	Maintenance Engineer
L. Mott	Project Designer, Unit 2
J. Mueller	Plant Manager, Unit 2
R. Orcutt	Superintendent, Power Dept.
A. Pinter	Site Licensing Engineer
A. Raju	Electrical Engineer, NMPC EDSFI Team Leader
L. Schiavone	Mechanical Design Engineer
C. Terry	Vice President, Nuclear Engineering
K. Ward	Manager, Engineering, Unit 2
A. Zallnick Jr.	Supervisor, Unit 2 Licensing

Contractors

R. Das	ASTA Engineering
G. Morris	Ogden Engineering

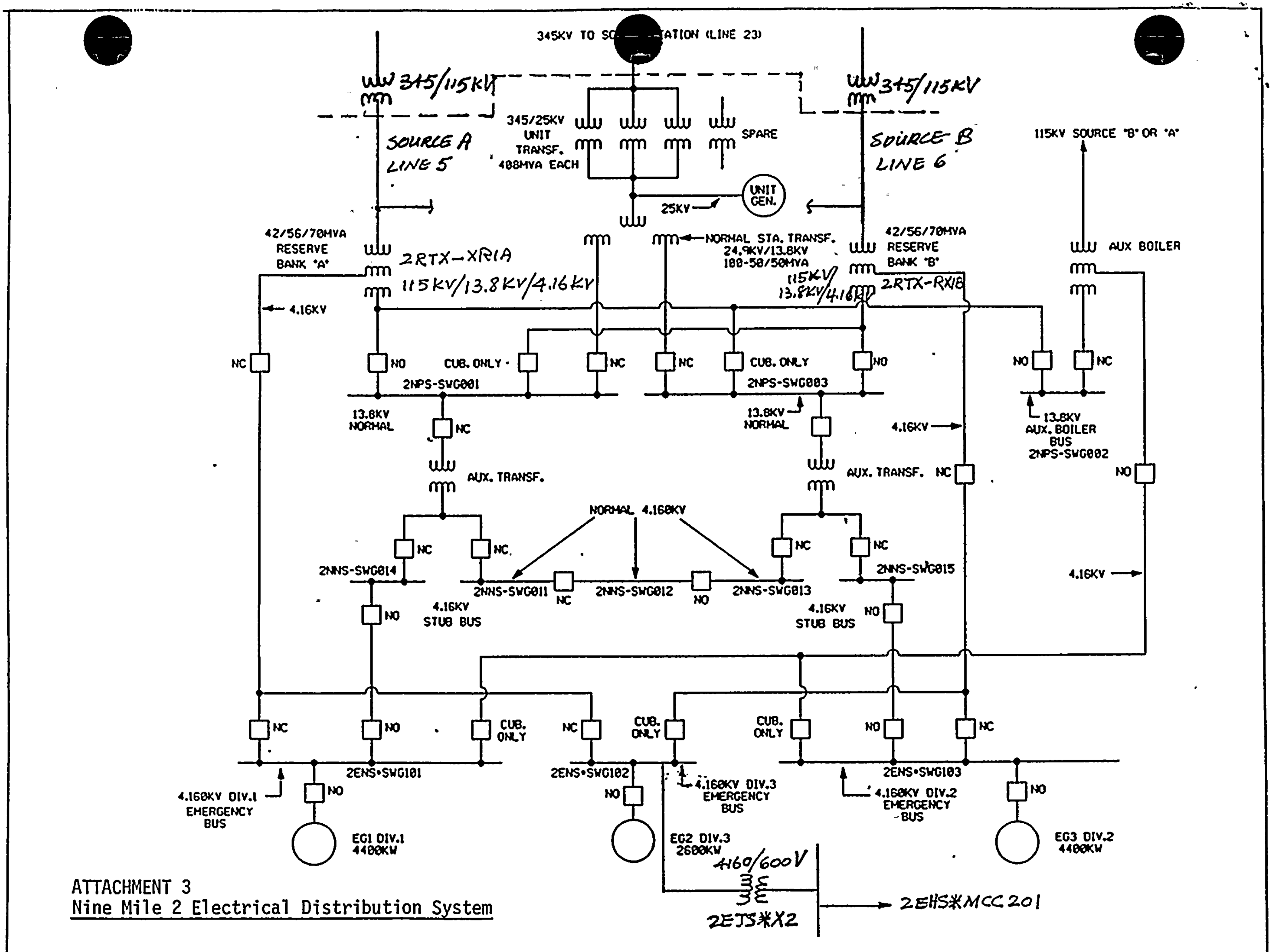
U.S. Nuclear Regulatory Commission

W. Mattingly	NRC Resident Inspector
J. Menning	Project Manager, NRR
B. Norris	Senior Resident Inspector
W. Ruland	Chief, Electrical Section, DRS

ATTACHMENT 2

Abbreviations

A or Amp	Amperes
ac	Alternating Current
BHP or bhp	Brake Horsepower
BIL	Basic Insulation Level
BOP	Balance of Plant
CB	Circuit Breaker
CFR	Code of Federal Regulations
dc	Direct Current
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GE	General Electric
gpm	Gallons Per Minute
HPCS	High Pressure Core Spray
HVAC	Heating Ventilation and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
kA	Kiloamperes
kV	Kilovolts
kVA	Kilovolt-amperes
kW	Kilowatts
LC	Load Center
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MOV	Motor-Operated Valve
NSSS	Nuclear Steam Supply System
PSI or psi	Pounds per Square Inch
RG	USNRC Regulatory Guide
rms	Root Mean Square
RSST	Reserve Station Service Transformer
THD	Total Harmonic Distortion
TS	Technical Specifications
UPS	Uninterruptible Power Supply
USNRC	United States Nuclear Regulatory Commission
UST	Unit Service Transformer(s)
UV	Undervoltage
V	Volt(s)
Vac	Volts Alternating Current
Vdc	Volts Direct Current



ATTACHMENT 3
Nine Mile 2 Electrical Distribution System

SK052.DGN