U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	January 4 - February 14, 1998
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/98-01 & 50-410/98-01
January 4 - February 14, 1998

This NRC inspection report includes reviews of licensee activities in the functional areas of operations, engineering, maintenance, and plant support. The report covers a six-week period of inspections and reviews by the resident staff.

PLANT OPERATIONS

Unit 2 operators responded appropriately to the failure of the Division II containment atmosphere gaseous/particulate radiation monitor that occurred while the Division I monitor was inoperable for maintenance. Station Operations Review Committee members maintained the proper safety focus during the meeting to discuss the basis for requesting enforcement discretion.

Routine monitoring of the Unit 2 fuel reliability index allowed NMPC to identify a reactor fuel leak early, before it degraded any further. The flux tilting and power suppression evolution was methodical and well-controlled due, in part, to good communication and coordination among all involved organizations. NMPC took aggressive actions to prevent further leak degradation.

During an inspection in the Unit 2 residual heat removal pump rooms, the inspectors identified inadequate separation between conduits for safety-related temperature elements of different divisions. (NCV) A breakdown in communications between an Assistant Station Shift Supervisor and a system engineer resulted in a one week delay in recognizing the impact that inadequate conduit separation had on the operability of safety-related plant equipment.

Most catch containments installed in Unit 1 were adequately installed and maintained. However, many designated as "permanent" did not have an engineering evaluation to determine if a plant change or modification was required. (NCV) The most recent semi-annual catch containment review lacked depth, in that NMPC failed to fully evaluate whether catch containments should be removed or that those designated as "permanent" had the required engineering evaluation.

The quarterly reviews of extended markups at Unit 1 were weak in that the reviewers failed to identify numerous markup discrepancies that were later identified by the inspectors. Unit 1 management was aware of the weaknesses, and proposed corrective actions appeared appropriate.

MAINTENANCE

NMPC appropriately evaluated the impact of a leaking fuel delivery valve on the operability of the Unit 2 emergency diesel generator.

Based upon the NRC inspectors' questions, NMPC management declared the Unit 1 liquid poison system inoperable. Portions of the system piping had not been periodically flow tested and NMPC was unable to readily ascertain whether the piping from the liquid poison tank to the pump suction valves was obstructed. NMPC's decision to declare the liquid poison system inoperable and commence a shutdown was conservative, and the actions taken to test the system were appropriate. The special evolution brief was thorough. Although the previous Unit 1 liquid poison system surveillance testing met technical specification requirements, the testing was inadequate to verify system operability. (VIO)

ENGINEERING

As a result of a good questioning attitude by a system engineer, NMPC identified that maintenance on the Unit 1 service water drag valve in the reactor building violated secondary containment integrity. Past maintenance on the valve exceeded the allowable limiting condition for operation outage time, and a reactor shutdown had not been initiated in accordance with the technical specification requirements. (NCV) The inspectors identified that NMPC failed to perform a design change for permanently installed scaffolding. (NCV)

The inspectors identified that the temperature control valve for the Unit 1 control room emergency ventilation system had been inoperable since 1983. The administrative controls to disposition the failed valve had not been properly implemented; i.e., the controlled drawings did not indicate the inoperable valve, nor was an engineering evaluation performed, as required by procedures, to determine if continued operation with the degraded condition was acceptable. (VIO)

Prior to April 30, 1992, Unit 2 operated with circuit breakers in the racked out position, and failed to recognize the adverse impact on switchgear seismic qualification and, therefore, switchgear operability. (NCV) Although NMPC took appropriate actions in 1992 to preclude future operations with breakers in the racked out position, they failed to recognize that they were in an unanalyzed condition, and that the condition was reportable. (NCV)

NMPC identified that a portion of the Unit 2 testing for the recirculation pump trip in response to an anticipated transient without scram was not completed in accordance with the technical specifications. (NCV) Specifically, the logic system functional testing failed to include the high reactor pressure trip of the low frequency motor generator. In addition, the failure to specify an acceptability range for the low frequency motor generator time delay in the subsequent procedure change procedure indicated weaknesses in the procedure and in the review of the associated procedure change. Furthermore, in December 1996, NMPC missed an opportunity to identify the inadequate surveillance test due to a non-conservative interpretation of the Updated Final Safety Analysis Report.

The licensee's actions at both units to address an industry concern with potentially defective emergency diesel generator air start solenoid valves was timely and technically sound.

NMPC responded quickly and appropriately to a vendor notification related to a possible failure of spring-return switches used in the emergency cooling and containment spray systems at Unit 1. Control room operators were aware of the potential failure mode; however, the associated operating procedures had not been revised to include a precautionary note related to the concern.

PLANT SUPPORT

Control room and fire brigade personnel appropriately responded to numerous Unit 1 fire alarm actuations, and the investigation effort appeared adequately coordinated. The failure to fully investigate and resolve previous similar false fire protection system actuations was a weakness and likely contributed to the recent event. Although Unit 1 fire suppression system operability did not appear to be affected by degraded components, the impact of the deficiencies could hinder plant personnel responding to an in-plant fire due to potential multiple false alarms.

REPORT DETAILS

Nine Mile Point Units 1 and 2
50-220/98-01 & 50-410/98-01
January 4 - February 14, 1998

SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) started the inspection period at full power. On the morning of January 21, 1998, the licensee commenced a unit shutdown due to the liquid poison system being inoperable (Section M2.1 of this report). Reactor power was reduced to approximately 70% when the operability of the liquid poison system was confirmed; full power was achieved later that day. The unit remained at full power throughout the remainder of the inspection period.

Unit 2

Nine Mile Point Unit 2 (Unit 2) started the inspection period at 95% power, limited to 95% due to the moisture separator reheaters being removed from service. On January 7, 1998, the licensee commenced a unit shutdown due to both drywell radiation monitors being out-of-service (Section O1.2 of this report); reactor power was lowered to approximately 50%. During the power reduction, NMPC requested, and was granted, enforcement discretion by the NRC. The unit was returned to 95% power on January 8. On January 24, reactor power was again reduced to approximately 50% to identify the source of a potential fuel leak (Section O1.3 of this report). The unit was returned to 95% on January 30. On February 14, reactor power was lowered to approximately 81% to perform a rod pattern adjustment, and this power level was maintained through the remainder of the inspection period.

Management Reorganization

On January 23, 1998, Mr. John H. Mueller assumed the position of Senior Vice President and Chief Nuclear Officer of NMPC. Mr. Mueller succeeded Mr. B. Ralph Sylvia.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC resident inspectors conducted inspection activities during normal, backshift, and deep backshift hours. The results of the inspection activities are contained in the applicable sections of this report.

Updated Final Safety Analysis Report Reviews

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) related to the

areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. Exceptions noted were: (1) the conduit for safety-related residual heat removal temperature elements of different electrical divisions were in contact, although the Unit 2 UFSAR specifies a minimum conduit-to-conduit physical separation of ½-inch (Section O2.1 of this report); and (2) the logic system functional testing of the anticipated transient without scram-recirculation pump trip of the low frequency motor generator on high pressure had not been performed due to a non-conservative interpretation of the Unit 2 UFSAR (Section E8.3 of this report).

I. OPERATIONS

O1 Conduct of Operations (71707) [1]

O1.1 General Comments

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations to verify that the units were operated safely and in accordance with licensee procedures and regulatory requirements. The reviews included tours of both accessible and normally inaccessible areas of both units, verification of engineered safeguards features (ESF) system operability, verification of adequate control room and shift staffing, verification that the units were operated in conformance with technical specifications, and verification that logs and records accurately identified equipment status or deficiencies. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Initiation of a Unit 2 Plant Shutdown due to Inoperable Containment Atmospheric Gaseous/Particulate Radiation Monitors

a. Inspection Scope

The inspectors assessed NMPC's performance in response to a failure of the Division II containment atmosphere gaseous/particulate radiation monitor concurrent with the Division I monitor being inoperable for preplanned maintenance. The inspectors observed Unit 2 control room troubleshooting activities and initiation of the reactor shutdown. The inspectors reviewed the Station Shift Supervisor's (SSS) logs, applicable procedures, and technical specifications (TS), and discussed related issues with on-duty operators, technicians, and management. In addition, discussions were held with NRC management and technical staff members from the Region I Office and the Office of Nuclear Reactor Regulations (NRR) with regard to enforcement discretion.

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[1] Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics. The NRC inspection manual procedure or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section.

b. Observations and Findings

On January 7, 1998, at 4:41 a.m., Unit 2 experienced a failure of the Division II containment atmosphere gaseous/particulate radiation monitor (2CMS*CAB10B). At the same time, the redundant Division I radiation monitor (2CMS*CAB10A) was out-of-service for maintenance to replace a portion of the heat trace circuitry. With both divisions of containment radiation monitoring inoperable, the Unit 2 operators entered TS 3.0.3, which required actions be initiated within one hour to shutdown the reactor, and to place the mode switch in STARTUP within the next 6 hours. At 5:35 a.m., the operators commenced a reactor shutdown.

Attempts to return 2CMS*CAB10A to service were unsuccessful. The licensee's initial troubleshooting determined that both divisions of containment radiation monitoring failed due to moisture intrusion. NMPC determined that they would not be able to return the monitors to an operable status within the 6-hours allowed by TS before having to complete the reactor shutdown. Therefore, NMPC notified the NRC and requested enforcement discretion to delay the shutdown during restoration of the equipment, and avoid an unnecessary plant shutdown. NMPC continued to reduce reactor power and, at 11:23 a.m., with the reactor at 50% power, Region I verbally granted enforcement discretion from the TS requirements until 9:00 a.m. on January 8, 1998. The enforcement discretion was granted provided that during the discretionary period: (1) drywell atmospheric grab samples would be taken and analyzed every 12 hours, and (2) primary containment floor and equipment drain leakage detection systems would be monitored every 4 hours. Subsequently, on January 9, 1998, a written Notice of Enforcement Discretion (NOED) was issued.

Further licensee troubleshooting determined that 2CMS*CAB10B (Division II) failed due to a defective flow control transducer board, and not due to moisture intrusion. The board was replaced, and the monitor was calibrated and returned to service on January 7, 1998, at 6:20 p.m. Restoration of the Division II monitor allowed NMPC to exit the TS shutdown actions and eliminated the continued need for NRC enforcement discretion. 2CMS*CAB10A was returned to an operable status on January 9, 1998.

The inspectors observed control room activities shortly after Unit 2 operators identified that 2CMS*CAB10B had failed. The operators' actions were consistent with the licensee's procedures and TSs. Troubleshooting and repair activities were methodical. The inspectors observed the Unit 2 Station Operating Review Committee (SORC) meeting that discussed the basis for requesting enforcement discretion and noted that the SORC members maintained the proper safety focus throughout the meeting. In addition, during the period enforcement discretion was granted, the inspectors verified that the drywell atmospheric grab samples were taken and analyzed every 12 hours, and that the primary containment floor and equipment drain leakage detection system were monitored every 4 hours.

c. Conclusion

Unit 2 operators responded appropriately to the failure of the Division II containment atmosphere gaseous/particulate radiation monitor that occurred while the Division I monitor was inoperable for maintenance. SORC members maintained the proper safety focus during the meeting to discuss the basis for requesting enforcement discretion.

O1.3 Identification of a Reactor Fuel Leak at Unit 2

a. Inspection Scope

The inspectors assessed NMPC's identification of a reactor fuel leak at Unit 2, and subsequent actions to address the leak. The inspectors reviewed plant operating data, licensee procedures, and other related documentation, including the Unit 2 UFSAR. The inspectors observed portions of the flux tilting and power suppression evolution. Additionally, the inspectors discussed the issue with the Unit 2 Plant Manager and Operations Manager, and members of the reactor engineering and radiation monitor calibration groups.

b. Observations and Findings

On January 16, 1998, NMPC concluded that a reactor fuel leak had developed at Unit 2. This was based on a small increase in the fuel reliability index (FRI). The FRI is an analysis of xenon isotopes present in offgas samples, and is used to provide indication of fuel failure. The FRI is performed weekly at both units. The FRI on January 10, 1998, was 75 microcuries per second (μCi/sec), which was a significant increase over the previous readings that ranged between 10 and 20 μCi/sec. However, offgas activity remained relatively steady. NMPC discussed the indications with General Electric (GE) and, on January 16, concluded that a small fuel leak existed and had probably developed late in December 1997.

Based on the increase in FRI, NMPC initiated the "Level 1" actions, as described in Procedure FRG-1, "Fuel Reliability Guidelines." The initiation of Level 1 actions was conservative since FRG-1 defines a Level 1 condition as a FRI greater than 100 μCi/sec above the cycle baseline. Plans were developed to locate the fuel leak(s) and to suppress the power in the vicinity of the leak(s). During the interim, control rod movement at Unit 2 was minimized to avoid aggravating the leak.

To facilitate locating the leaking fuel, NMPC connected a continuous on-line isotopic monitor. The isotopic monitor alleviated the need to obtain and analyze chemistry samples, therefore minimizing the time between control rod manipulations. The on-line isotopic monitoring equipment required changes to the Unit 2 UFSAR sections associated with the plant radiation monitors. The changes were reviewed in accordance with Title 10 of the Code of Federal Regulations, Part 50.59 (10 CFR 50.59). Additionally, NMPC Procedure N2-REP-31, "Power Suppression Testing," was revised to incorporate the use of the on-line isotopic monitoring equipment.

The inspectors reviewed these changes, including the 10 CFR 50.59 safety evaluation, and found them acceptable.

On January 23, Unit 2 operators commenced a down power to 55% and began power suppression testing in accordance with Procedure N2-REP-31. The purpose of the test was to identify the location of the fuel leaks by varying power through control rod movement and observing offgas radiation changes. NMPC considered this test a special evolution, as defined in Procedure GAP-SAT-03, "Control of Special Evolutions." The inspectors observed that appropriate management oversight was present during the test. The inspectors also observed that the test was conducted in a methodical manner and was well-controlled due, in part, to good communication and coordination among all involved organizations.

The testing was completed on January 27, and data indicated that only one location within the core had fuel rod leakage. The suspected location was between control rods 18-27, 14-27 and 14-23, with the greatest indications near control rod 18-27. Following the testing, these three control rods were left completely inserted to suppress the power in the location of the fuel leak. Subsequently, reactor power was slowly returned to full power (95%), so as not to further aggravate the fuel leak. The next weekly FRI was within the normal 10 to 20 μCi/sec range, indicating that the power suppression was successful.

Historically, BWRs are normally operated with a symmetric control rod pattern. This was necessary to determine reactor core thermal power, since the computer program used core mirror imaging in the calculations. However, operating with three adjacent control rods inserted to suppress the fuel leak resulted in an asymmetric control rod pattern. Unit 2 had previously updated their three dimensional reactor core monitoring (3D Monicore) computer program to the "Baseline 94" version. This allowed the 3D Monicore program to automatically account for asymmetric rod patterns. The inspectors discussed the unusual rod pattern with Unit 2 reactor engineering personnel and reviewed supporting documentation from GE, and no concerns were identified.

c. <u>Conclusion</u>

Routine monitoring of the Unit 2 fuel reliability index allowed NMPC to identify a reactor fuel leak early, before it degraded any further. The flux tilting and power suppression evolution was methodical and well-controlled due, in part, to good communication and coordination among all involved organizations. NMPC took aggressive actions to prevent further leak degradation.

O1.4 <u>Inadequate Shift Turnover for Unit 1 Reactor Operator</u>

During a tour of the Unit 1 control room soon after shift turnover, chief station operator (CSO), a licensed reactor operator (RO), was questioned by the inspectors as to the status of #122 emergency cooling (EC) condenser radiation monitor, which was inoperable due to a failed surveillance test. The CSO had not been informed by the off-going CSO during the shift turnover that the monitor was

inoperable. The inspectors discussed this weakness with the SSS and the Unit 1 Operations Manager. Both concurred with the inspectors conclusion that the shift turnover by the off-going CSO was weak.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Inadequate Separation Between Conduits for Safety-Related Temperature Elements

a. Inspection Scope

During a visual inspection of equipment within the Unit 2 residual heat removal (RHR) pump rooms, the inspectors questioned the physical separation between conduits for safety-related temperature elements of different electrical divisions. The inspectors assessed the licensee's actions to correct the condition, and reviewed the applicable sections of the UFSAR and associated plant drawings.

b. Observations and Findings

On January 30, 1998, the inspectors identified that the conduit for temperature element 2RHS*TE49A was touching the conduit for temperature element 2RHS*TE49B. These temperature elements are powered from Division I and Division II, respectively, and provided containment isolation signals for shutdown cooling valves (Group 5) and reactor core isolation cooling (RCIC) steam supply valves (Group 10). The inspectors were concerned that a fault in one division could potentially impact the other division due to the inadequate separation. This concern was discussed with the on-watch Assistant Station Shift Supervisor (ASSS).

The initial response was that the Unit 2 system engineers concluded no problem existed. The inspectors questioned the basis for this conclusion, and learned that there was a breakdown in communications between the ASSS and the system engineers. Specifically, the system engineers understood the problem to be with the temperature elements and not with the conduit. On February 6, the system engineering staff identified the location where the conduits were touching and informed the control room. The on-watch operators declared the two temperature elements inoperable, and took the actions required by the TS. In addition, NMPC notified the NRC in accordance with 10 CFR 50.72. Work order (WO) 98-01546-00 was generated and proper separation was established.

The inspectors reviewed the applicable plant drawings with members of the system engineer staff and determined that a fault impacting both divisions would be no worse than a fault impacting only one division. This was because: (1) each temperature element provided a signal to both containment isolation groups (Groups 5 and 10); (2) the containment isolation system logic only required one signal for actuation; and (3) the containment isolation system logic was designed as fail safe.

The Unit 2 UFSAR, Section 8.3.1.4.2, "Physical Separation," specified a minimum conduit-to-conduit separation of ½-inch. The failure to maintain the Unit 2 plant configuration in accordance with the specification provided within the UFSAR is a

violation of 10 CFR 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Criterion III, "Design Control." This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-410/98-01-01)**

c. Conclusion

During an inspection in the Unit 2 residual heat removal pump rooms, the inspectors identified inadequate separation between conduits for safety-related temperature elements of different divisions. (NCV) A breakdown in communications between an Assistant Station Shift Supervisor and a system engineer resulted in a one week delay in recognizing the impact that inadequate conduit separation had on the operability of safety-related plant equipment.

O2.2 Control of Catch Containments at Unit 1

a. Inspection Scope

The inspectors reviewed the catch containment tracking log maintained in the Unit 1 control room and performed a random sampling of catch containments installed in the plant to assess the adequacy of administrative controls for catch containment installation and removal. Issues were subsequently discussed with operations personnel.

b. Observations and Findings

During routine plant walkdowns of the Unit 1 reactor and turbine buildings, the inspectors examined installed catch containments. A catch containment is a device installed below plant equipment to divert or contain water typically resulting from component leakage or condensation. The inspectors observed that, generally, catch containments were adequately installed and maintained in accordance with NMPC Procedure GAP-OPS-04, "Control of Catch Containments."

The inspectors reviewed the catch containment tracking log maintained in the Unit 1 control room and identified that the log accurately reflected the catch containments installed in the plant. The inspectors observed that many of the catch containments in the log were greater than five years old; approximately one-half of the current fifty-four catch containments were installed between 1990 and 1993. These older catch containments were installed either to collect condensation or were awaiting disposition as a "permanent" plant change.

GAP-OPS-04, Section 3.1.4, required that a catch containment designated as "permanent" be assessed by system engineering to determine if a plant change was desired and to initiate a modification as required. The procedure required a determination as to the continued need for each catch containment. The inspectors identified that many of the catch containments designated as "permanent" did not have documented engineering evaluations performed to determine if a plant change

or modification was required. This failure to perform an engineering evaluation as required by GAP-OPS-04 constitutes a violation of minor significance and is being treated as a Non-Cited Violation consistent with Section IV of the NRC Enforcement Policy. (NCV 50-220/98-01-02)

The inspectors identified that the required semi-annual catch containment review had last been performed in October 1997. The inspectors considered the review to lack sufficient depth, in that the licensee failed to fully evaluate whether catch containments should be removed or that those catch containments designated as "permanent" had the required engineering evaluation performed. Operations staff acknowledged that catch containments were not being effectively removed or adequately evaluated for permanent installation. A Deviation/Event Report (DER 1-98-0078) was issued to address this concern, and the licensee performed a detailed catch containment review. The Unit 1 Operations Manager directed that the catch containment tracking log be updated and modified to ensure better personnel responsibility and accountability for each log entry, and to provide sufficient information for determining the status of engineering evaluations. Subsequently, approximately twenty-two catch containments were removed from the reactor and turbine buildings.

c. Conclusions

Most catch containments installed in Unit 1 were adequately installed and maintained. However, many designated as "permanent" did not have an engineering evaluation to determine if a plant change or modification was required. (NCV) The most recent semi-annual catch containment review lacked depth, in that NMPC failed to fully evaluate whether catch containments should be removed or that those designated as "permanent" had the required engineering evaluation.

O2.3 Review of Unit 1 Extended Markup/Holdout Quarterly Report

a. Inspection Scope

The inspectors reviewed the Unit 1 extended markup/control tag/holdout quarterly audit report and discussed findings with the Shift Technical Advisor (STA).

b. Observations and Findings

The inspectors reviewed the Unit 1 quarterly audit report of extended markups, control tags, and holdouts. The quarterly audit was used to determine the continued need and applicability of each current markup on file and to ensure that discrepancies are documented. Unit 1 Procedure N1-PM-Q2, "Periodic Review of Hazardous Energy and Configuration Tagging System," provided the administrative controls for completing the quarterly audit, which was last completed on January 15, 1998.

The inspectors discussed the results with the STA, who was responsible for coordinating the review and maintaining the quarterly audit report. The inspectors

noted many weaknesses in the maintenance of the audit report, such as: (1) the associated work documents were not current, (2) the individual responsible for completing the required work was either not listed or the name was not current, and (3) the expected work completion date was either incomplete or indeterminate. The Unit 1 Plant Manager informed the inspectors that most equipment with longstanding unavailability was not receiving engineering reviews or Plant Manager concurrences, as required by NMPC Procedure NIP-ECA-01, "Deviation/Event Report." A specific example of this is a longstanding holdout on the control room emergency ventilation system, as discussed in Section E2.2 of this inspection report.

The inspectors discussed the program implementation weaknesses with the Unit 1 Operations Manager. The Operations Manager was aware of the weaknesses, which also included the administrative tracking of control room deficiencies, operator work-arounds, and catch containments (previously discussed in Section O2.2). The Operations Manager issued an internal memorandum to Unit 1 management and Operations department supervisors that delegated the responsibility for tracking these issues to the STAs. Also, a meeting was held to discuss past programmatic weaknesses in tracking of longstanding holdouts. A draft revision to the quarterly audit report was presented at this meeting, and included a tracking mechanism for ensuring applicability reviews and safety evaluations were completed. The inspectors considered these changes to be appropriate.

c. <u>Conclusions</u>

The quarterly reviews of extended markups at Unit 1 were weak in that the reviewers failed to identify numerous markup discrepancies that were later identified by the inspectors. Unit 1 management was aware of the weaknesses, and proposed corrective actions appeared appropriate.

O8 Miscellaneous Operations Issues (92901)

O8.1 <u>(Closed) LER 50-410/98-01: Entry into TS 3.0.3 Due to Containment Atmospheric Gaseous/Particulate Radiation Monitors Inoperable</u>

The technical issues associated with this licensee event report (LER) were described in Section O1.2 of this inspection report. The inspectors verified that the LER was completed in accordance with the requirements of 10 CFR 50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause, and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (61726, 62707)

M1.1 General Comments

Using NRC Inspection Procedures 61726 and 62707, the resident inspectors periodically observed plant maintenance activities and the performance of various surveillance tests. As part of the observations, the inspectors evaluated the activities with respect to the requirements of the Maintenance Rule, as detailed in Title 10 of the Code of Federal Regulations, Part 50.65 (10 CFR 50.65). In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures in use at the work site, and with the appropriate focus on safety. Specific activities and noteworthy observations are detailed in the inspection report. The inspectors reviewed procedures and observed all or portions of the following maintenance/surveillance activities:

- WO 94-101-01 — TCV 210.1-56 to be Retired in Place
- WO 98-00279-00 — Repair Leaky Delivery Valve on Division I EDG
- WO 98-509-02 — Clean Reactor Building
- N1-MMP-072-247 — Service Water Temperature Control Valve TCV-72-146 (RBCLC) and TCV-72-147 (TBCLC) Maintenance
- N1-MAP-MAI-0301 — Scaffold Control
- N2-OSP-ENS-M001 — 4.16 kV Emergency Bus Under and Degraded Voltage Functional Test
- N2-ISP-RDS-Q106 — Quarterly Functional/Calibration of Control Rod Block Scram Discharge Volume High Water Level Instrument Channel
- N2-ISP-CMS-M@001 — Suppression Pool Water Temperature Calibration

M1.2 Replacement of Leaking Fuel Delivery Valve on a Unit 2 EDG

a. Inspection Scope

The inspectors observed the Unit 2 maintenance activities associated with the replacement of a leaking fuel delivery valve on the one emergency diesel generator

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[2] Surveillance activities are included under "Maintenance." For example, a section involving surveillance observations might be included as a separate sub-topic under M1, "Conduct of Maintenance."

(EDG). Additionally, the inspectors reviewed the applicable WO and discussed related issues with the SSS, system engineer, and maintenance supervisor.

b. Observations and Findings

On January 6, 1998, Unit 2 operators declared the Division I EDG inoperable for pre-planned maintenance. TS 3.8.1.1 allows the Division I EDG to be inoperable provided that it is restored to operable within 72 hours; otherwise, the plant is to be in at least hot shutdown within the next 12 hours. Due to unforeseen events, including an unexpected trip of the EDG due to a failed optical isolator transmitter board (see Section E8.9), the maintenance activities were not completed until the morning of January 9. During the post-maintenance surveillance test of the EDG, one of the fuel delivery valves developed a leak. Although the surveillance test was considered satisfactory, the SSS decided that the EDG would remain inoperable until the valve was replaced and tested. This decision was made about the same time the 72-hour portion of the TS limiting condition for operation (LCO) expired. NMPC determined that no immediate actions would be necessary to shutdown the reactor, since the time to replace and test the valve was expected to be short.

The inspectors observed the valve replacement. The activity was completed in accordance with WO 98-00279-00. Proper Quality Assurance (QA) and management oversight were noted during the activity. Upon completion of a satisfactory post-maintenance test, the SSS declared the EDG operable and exited the LCO action statement.

The Unit 2 EDG system engineer informed the inspectors that cracking of fuel delivery valves was an industry concern, initially identified in May 1996. As a result, NMPC initiated DER 2-96-1275 to evaluate the consequences of delivery valve failures and determined there was no adverse impact on EDG operability. NMPC had planned to replace all the suspect valves in October 1996, but the valves of newer design were not available for installation. Since then, NMPC has received the new valves, and plans to install them during the next refueling outage. The inspectors reviewed DER 2-96-1275 and the associated engineering supporting analysis (ESA), which justified EDG operability with the suspect valves, and the inspectors considered the licensee's actions to be acceptable.

c. Conclusion

NMPC appropriately evaluated the impact of a leaking fuel delivery valve on the operability of the Unit 2 emergency diesel generator.

M2 Maintenance and Material Condition of Facilities and Equipment (61726)

M2.1 Unit 1 Liquid Poison System Surveillance Testing Deficiency

a. Inspection Scope

NMPC initiated a normal reactor shutdown of Unit 1 based on the liquid poison system being declared inoperable due to a section of piping not being previously tested. The inspectors discussed the issue with the Unit 1 Operations Manager and the system engineer, and reviewed the event notification.

b. Observations and Findings

In the summer of 1997, the inspectors had monitored a monthly surveillance test of the Unit 1 liquid poison system. The inspectors, through discussions with operators and the inservice testing (IST) supervisor, identified that all current liquid poison system surveillance tests were performed with the liquid poison pumps taking a suction from a test tank filled with demineralized water. This system configuration maintained the pump suction valves closed, and isolated the section of piping from the liquid poison tank to the pump suction valves. The inspectors questioned the IST supervisor as to whether the liquid poison system had been periodically tested to confirm adequate flow through this piping. The supervisor was unable to determine whether that section of piping had ever been previously tested.

NMPC initially did not question system operability. This determination was based upon the current surveillance testing meeting the requirements in the TSs and UFSAR, that the system design included tank heaters and temperature indicators, and that the piping under concern was insulated and heat-traced. However, the IST supervisor informed the inspectors that Unit 2 TSs required periodic flow verification through the section of piping from the liquid poison tank to the pumps, at least every eighteen months, to ensure the system was unobstructed. The IST supervisor also contacted other nuclear facilities to determine if this section of piping was periodically tested throughout the industry. Based upon this further information from these facilities, the IST supervisor informed the inspectors that a procedure would be developed to periodically take suction from the liquid poison tank, and that the procedure would most likely be conducted during the next refueling outage.

In January 1998, the inspectors queried Unit 1 staff as to the status of the proposed liquid poison system surveillance test procedure. The inspectors question received a higher level of NMPC management attention. After subsequent management review, NMPC concluded that the ability to readily ascertain whether the piping from the liquid poison tank to the pump suction valves was unobstructed was in question, and the system was declared inoperable on January 21, at 7:35 a.m. The licensee commenced a normal orderly shutdown within one hour of declaring the system inoperable, as required by Unit 1 TS 3.1.2.e. The inspectors considered the licensee's decision to declare the liquid poison system inoperable

and commence a shutdown to be conservative, and the actions to test the system to be appropriate.

In parallel with the shutdown, the licensee developed and approved a surveillance test to verify system flow when taking suction from the liquid poison tank. The inspectors observed the special evolution brief conducted prior to performing the test. The senior manager and the principal test engineer for the brief were the Unit 1 Operations Manager and an off-shift Senior Reactor Operator, respectively. The inspectors considered the special evolution brief to be thorough, in that it detailed the purpose of the test and emphasized procedural adherence, communications, and abort criteria. The inspectors monitored the special evolution locally in the reactor building, and determined that NMPC personnel performed the test adequately. The test results confirmed that no obstruction existed, and that the liquid poison system could establish adequate flow when taking suction from the liquid poison tank. The test results received a timely and adequate supervisory review and the liquid poison system was declared operable at 2:30 p.m. The shutdown was discontinued and power ascension commenced, with full power achieved at 4:35 p.m.

The Operations Manager informed the inspectors that routine performance of this test would occur on a cyclic basis. The inspectors agreed with NMPC that the testing requirements for the liquid poison system, as discussed in Unit 1 TSs and the UFSAR, had been met. However, the lack of a questioning attitude to routinely demonstrate that the entire liquid poison system was capable of performing the required function was considered a weakness. The failure to periodically verify that the liquid poison system was operable from the liquid poison tank to the pump suction valves is a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control," which requires that a test program be established to assure that all testing required to demonstrate a system will perform satisfactorily in service is identified and performed in accordance with written procedures. **(VIO 50-220/98-01-03)**

c. <u>Conclusions</u>

Based upon inspectors questions, NMPC management declared the Unit 1 liquid poison system inoperable. Portions of the system piping had not been periodically flow tested and NMPC was unable to readily ascertain whether the piping from the liquid poison tank to the pump suction valves was obstructed. NMPC's decision to declare the liquid poison system inoperable and commence a shutdown was conservative, and the actions taken to test the system were appropriate. The special evolution brief was thorough. Although the previous Unit 1 liquid poison system surveillance testing met technical specification requirements, the testing was inadequate to verify system operability. (VIO)

M8 **Miscellaneous Maintenance Issues (92700, 92902)**

M8.1 Administrative Closure of Escalated Enforcement Items

The escalated enforcement items (EEIs) listed below are being administratively closed, due to the issuance of the indicated enforcement action (EA) letter and associated determination.

EEI 50-220/96-12-01:	closed by EA 97-007, VIO 1013
EEI 50-220/96-12-05:	closed by EA 97-007, VIO 1023
EEI 50-220/96-12-06:	closed by EA 97-007, withdrawn
EEI 50-220/96-12-07:	closed by EA 97-007, withdrawn

III. ENGINEERING

E1 **Conduct of Engineering (37551)**

E1.1 General Comments

Using NRC Inspection Procedure 37551, the resident inspectors frequently reviewed design and system engineering activities, including justifications for operability determinations, and the support by the engineering organizations to plant activities.

E2 **Engineering Support of Facilities and Equipment (37551)**

E2.1 Maintenance on Unit 1 Service Water Valve Violated Secondary Containment Integrity

a. Inspection Scope

During preparation for maintenance on a service water valve in the Unit 1 reactor building, NMPC identified that the maintenance had the potential to jeopardize secondary containment integrity. The inspectors discussed the issue with the SSS and the system engineer, reviewed the event notification and the revised WO, and observed the rescheduled maintenance activities on the service water valve.

b. Observations and Findings

On January 27, 1998, during preparations for routine maintenance on the Unit 1 reactor building service water drag valve (TCV-72-146), the system engineer for the service water system questioned whether the planned maintenance could jeopardize secondary containment (reactor building) integrity. On January 29, NMPC determined that the maintenance did provide a possible pathway to violate secondary containment, and placed the planned maintenance on hold. In addition, because this evolution was routinely performed, most recently on December 11,

1997, an event notification to the NRC was initiated in accordance with 10 CFR 50.72.

The planned maintenance was the routine replacement of the internal strainer in the drag valve; to perform this, the valve bonnet must be removed. Since there is no downstream valve, the drag valve cannot be isolated. Unit 1 TS, Section 3.4.1, limits the reactor building leakage rate to 1600 cubic feet per minute (cfm). If service water was lost during the maintenance, a pathway from the reactor building to the outside atmosphere would exist, exceeding the TS limit for reactor building leakage. Previously, the maintenance was performed without entering the associated LCO. The LCO allowed four hours to return the leakage rate to within allowable limits, or initiate a shutdown and be in cold shutdown within the next ten hours. Normally, the valve bonnet was removed for greater than four hours, thus exceeding the allowable LCO time frame. The failure to initiate an orderly shutdown after the bonnet was removed for greater than four hours was a violation of the Unit 1 TS, Section 3.4.1. This non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-220/98-01-04)**

The inspectors reviewed the associated work order (WO 98-00509-02), the mechanical maintenance procedure (N1-MMP-072-247), the markup (1-98-87), the service water system piping and instrumentation drawing (C-19022-C), and other related documentation. The inspectors observed performance of the drag valve strainer replacement on February 7. The WO was appropriately revised to include a statement of plant impact: "breaching of service water pressure boundary is a breach of secondary containment." Because of difficulties encountered in the past when removing the valve bonnet from the valve body, a jacking device was manufactured to aid in this portion of the task. In addition, to ensure that the bonnet would be removed for no more that four hours, the maintenance technicians conducted a "dry-run" of the evolution prior to performing the actual work. The inspectors noted several maintenance supervisors and managers present at the job-site observing the work. The inspectors considered the preplanning of the work and the dry-run to be significant contributors in being able to complete the work in less than two hours.

The inspectors identified that the attached permit for the scaffold being used for the maintenance indicated that the expected load was 600 pounds and that the scaffold was erected for an indefinite period of time. The inspectors discussed with one of the maintenance supervisors in the area the fact that the maintenance personnel and tools on the scaffold platform exceeded the expected load. The supervisor stated that this had been identified the day before, and that the actual capacity was 1050 pounds. The inspectors then questioned whether the scaffold had been analyzed for permanent installation. Review by NMPC identified that the scaffold had not been appropriately processed for permanent installation in accordance with Procedure N1-MAP-MAI-0301, "Scaffold Control," Revision 8; specifically, paragraph 1.2.2 requires that scaffolding used as a permanent platform be processed as a design change. DER 1-98-325 was initiated to document the problem and initiate corrective action. The failure to perform a design change for

the permanently installed scaffold constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/98-01-05)**

c. Conclusion

As a result of a good questioning attitude by a system engineer, NMPC identified that maintenance on the Unit 1 service water drag valve in the reactor building violated secondary containment integrity. Past maintenance on the valve exceeded the allowable limiting condition for operation outage time, and a reactor shutdown had not been initiated in accordance with the technical specification requirements. (NCV) The inspectors identified that NMPC failed to perform a design change for permanently installed scaffolding. (NCV)

E2.2 Longstanding Holdout on Temperature Control Valve for Unit 1 Control Room Emergency Ventilation System

a. Inspection Scope

The inspectors identified a yellow holdout on the control room emergency ventilation system (CREVS) temperature control valve (TCV) dating from 1992. The inspectors questioned the SSS and determined that the valve was inoperable. The inspectors reviewed the holdout log, the WO, the DER, the UFSAR, and the associated procedures.

b. Observations and Findings

During a tour of the Unit 1 control room, the inspectors identified a yellow holdout (YHO 1-92-10045) on the temperature control valve (TCV 210.1-56) for the CREVS. The YHO was dated January 16, 1992. Discussions with the SSS revealed that the TCV had been inoperable since the early 1980s.

The TCV is a three-way control valve for the chilled water to the control room ventilation area coolers. The TCV controller failed as a result of aging, and a one-for-one replacement was not available. In 1983, a bypass valve around TCV 210.1-56 was installed per modification N1-83-61. The bypass was to ensure maximum cooling and maintain the control room temperature below 75 degrees Fahrenheit, as stated in the UFSAR, for protection of vital equipment and personnel comfort. This portion of the ventilation system was also part of the control room emergency ventilation system (CREVS). The CREVS would be initiated if the radiation monitors in the ventilation intake from outside detected a high radiation level, such as the result of a main steam line break outside containment. WO 94-101-01 was initiated in 1994 to replace the TCV controller. In May 1996, DER 1-96-1223 was initiated to document the longstanding YHO, and to note that the system drawing failed to include the bypass valve or indicate that the TCV was failed open. The disposition for the DER was to retire the TCV in place; the DER also noted that a safety evaluation would be required since the TCV was shown on an UFSAR drawing. The scheduled completion date was December 18, 1997. The

DER further stated that the control room temperature could be regulated by positioning the ventilation dampers. The DER stated that engineering had evaluated that the current system operation would not impact the intent of the system design. The TCV was added to the "Plant Equipment Retirement List" per Technical Department Instruction N1-TDI-18, "Equipment Retirement." The Plant Equipment Retirement List was a tracking mechanism for out-of-service equipment, but the TDI still required documentation to be completed before the equipment was formally retired-in-place. As of the date of the inspection, no action had been taken to complete this documentation. Subsequent to the end of the inspection period, NMPC management decided to attempt to repair the valve or find a replacement controller, if possible.

NMPC Procedure GAP-DES-03, "Control of Temporary Modifications," defines temporarily lifted leads that modify the electrical circuit design or configuration as an example of a temporary modification. The procedure further states that temporary alterations identified and controlled by other administrative processes are exempt from the requirements of the procedure. However, GAP-DES-03, Section 1.2, specifically states that, even though excluded from the temporary modification procedure requirements, the exemptions are not excluded from the requirements of NMPC Procedure NIP-SEV-01, "Applicability Reviews and Safety Evaluations." As of the date of the inspection, NMPC had not performed either an applicability review or a safety evaluation. This is a violation of the Unit 1 TS, Section 6.8.1, which requires procedures to be implemented, as written. **(VIO 50-220/98-01-06)**

c. Conclusion

The inspectors identified that the temperature control valve for the Unit 1 control room emergency ventilation system had been inoperable since 1983. The administrative controls to disposition the failed valve had not been properly implemented; i.e., the controlled drawings did not indicate the inoperable valve, nor was an engineering evaluation performed, as required by procedures, to determine if continued operation with the degraded condition was acceptable. (VIO)

E8 Miscellaneous Engineering Issues (90712, 92700, 92903)

E8.1 (Closed) LER 50-410/97-05-01: High Pressure Core Spray System Inoperable Due to Failed Unit Cooler

The technical issues associated with this LER were described in NRC Inspection Report (IR) 50-410/97-04, Section O2.2. The inspectors completed an in-office review of the additional information provided in LER 50-410/97-05, Supplement 1, and found it acceptable. This LER is closed.

E8.2 (Closed) LER 50-220/97-10-01:TS Required Shutdown Due to Emergency Cooling Condenser Tube Leak

The technical issues associated with this LER were described in NRC IR 50-220/97-07, Section O1.2; NRC IR 50-220/97-11,Section M1.2; and NRC IR 50-220/97-12, Section E8.7. Subsequent to the original LER, the licensee identified additional information pertinent to the event and included that information in Supplement 1 to the LER. The inspectors performed an in-office review of the LER supplement.

NMPC concluded that the EC condenser tube failures resulted from a combination of thermal fatigue and intergranular stress corrosion cracking due to the upper tubes of the EC condenser tube bundles being in a continuous steam condensing mode. The licensee determined the root cause of the failed tubes resulted from an original design deficiency, in that the EC condenser return isolation valve leakage limitations were not specified. NMPC also stated that an opportunity was missed to identify this condition during a 1977 modification, in which an originally installed temperature alarm system was modified without a thorough understanding of the system design basis. This modification resulted in masking the normal operating water level in the EC condenser steam inlet piping.

The LER supplement further detailed isotopic analysis reviews by the Unit 1 chemistry department, and NMPC concluded that small EC condenser tube leaks likely existed since March 1996. NMPC also included in the LER supplement that: (1) dose calculations for the quarter ending September were well below TS offsite dose limits, (2) the EC system decay heat removal function was not significantly affected by the EC condenser tube degradation, and (3) the EC system station blackout and 10 CFR 50 Appendix R functions could have still been performed.

The inspectors verified that the LER supplement was completed in accordance with the requirements of 10 CFR 50.73. Specifically, the description and analysis of the event, as contained in the LER supplement, were consistent with the inspectors' understanding of the event. The inspectors considered the root cause and corrective and preventive actions as described in the supplement were reasonable. This LER supplement is closed.

E8.3 (Closed) LER 50-410/97-13: Prior to 1992, Emergency Switchgear Not Seismically Qualified With Breakers Racked Out

a. Inspection Scope

The inspectors reviewed the details associated with the LER and the applicable DER and procedures. In addition, the inspectors reviewed the LER to verify completion in accordance with 10 CFR 50.73.

b. Observations and Findings

On October 29, 1997, NMPC determined that prior to April 30, 1992, Unit 2 had racked out circuit breakers from 4160-volt switchgear such that the switchgear no longer met seismic requirements. The licensee identified this issue during a review of NRC Information Notice (IN) 97-53, "Circuit Breakers Left Racked Out in Non-Seismically Qualified Positions." A member of the Unit 2 operations support staff noted that other licensees had reported similar conditions, but no report could be located for Unit 2.

On March 27, 1992, while Unit 2 was shutdown for refueling, NMPC initiated DER 2-92-Q-1144 to address the seismic qualification of circuit breakers in the racked out condition. The initial SSS review of the DER concluded that operability and reportability determinations were not applicable. During the DER disposition, NMPC design engineering determined that the switchgear were only seismically qualified with the breakers racked in. Therefore, the switchgear would have been inoperable during situations with breakers racked out. Prior to April 30, 1992, the practice at Unit 2 was to rack out circuit breakers for an extended period, although the practice was limited to only one safety division at a time.

In 1997, NMPC concluded that prior to April 30, 1992, they had probably racked out breakers in excess of eight hours. When a division of AC [alternating current] was energized, Unit 2 TS 3.8.3.1 required the division to be reenergized within eight hours or be in at least HOT SHUTDOWN within the next twelve hours. Based on DER 2-92-Q-1144, NMPC revised the applicable procedures to halt the practice of leaving circuit breakers in the racked out position. The inspectors considered the actions taken to prevent recurrence to be appropriate and effective, based on current observations during plant tours. However, the failure to meet the requirements of TS 3.8.3.1, prior to April 30, 1992, was a violation. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/98-01-07)**

Although NMPC took adequate actions in 1992 to discontinue the practice of racking out breakers, they failed to recognize during their review that the practice had placed them in an unanalyzed condition, and that the condition was reportable. The failure to report an unanalyzed condition to the NRC is a violation of 10 CFR 50.72 and 50.73. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-410/98-01-08)** As described in the LER, the reason for not recognizing reportability could not be determined, but a contributing factor was that the DER process in 1992 was not clear relative to the reporting requirements. Since 1992, improvements have been made to the DER procedure, and plant personnel were trained on the reporting requirements. The inspectors have reviewed the DER procedure and considered the reportability guidance to be acceptable.

The inspectors verified that the LER was completed in accordance with the requirements of 10 CFR 50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

c. Conclusion

Prior to April 30, 1992, Unit 2 operated with circuit breakers in the racked out position, and failed to recognize the adverse impact on switchgear seismic qualification and, therefore, switchgear operability. (NCV) Although NMPC took appropriate actions in 1992 to preclude future operations with breakers in the racked out position, they failed to recognize that they were in an unanalyzed condition, and that the condition was reportable. (NCV)

E8.4 (Closed) LER 50-410/97-16: Missed TSSR 4.3.4.1.2 for ATWS-RPT Trip of LFMG

a. Inspection Scope

The inspectors reviewed the details associated with the LER and the applicable DERs, TSs and UFSAR sections. The inspectors reviewed surveillance test procedures and applicable plant drawings, and discussed with members of the NMPC engineering and licensing staffs the ATWS-related testing performed at Unit 2. In addition, the inspectors reviewed the LER to verify completion in accordance with 10 CFR 50.73.

b. Observations and Findings

While drafting the LCOs for the ATWS-RPT [anticipated transient without scram-recirculation pump trip] section of the Unit 2 improved technical specifications (ITS), NMPC noted that the current logic system functional testing (LSFT) for the ATWS-RPT did not include the trip of the low frequency motor generator (LFMG) on high reactor pressure, as described in the basis for the ITS. DER 2-97-3105 was initiated to document the concern, which was identified on November 7, 1997, while Unit 2 was shutdown for repair to a recirculation flow control valve. Although NMPC was evaluating whether testing was required by their current TSs, they made a one-time revision to the applicable surveillance test procedure and, on November 9, satisfactorily tested the trip of the LFMG on high reactor pressure. Subsequently, on December 3, 1997, NMPC determined that the LSFT of the ATWS-RPT of the LFMG trip for high reactor pressure was required by technical specification surveillance requirement (TSSR) 4.3.4.1.2.

The inspectors reviewed the applicable UFSAR and TS sections, and DERs. The inspectors determined that the failure to previously complete LSFT of the ATWS-RPT LFMG trip on high reactor pressure was a violation of TSSR 4.3.4.1.2. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. (NCV 50-410/98-01-09)

NMPC stated in the LER that the same issue had been previously reviewed through DER 2-96-3268, initiated in December 1996. During that review, NMPC had determined that testing of the ATWS-RPT LFMG trip on high reactor pressure was not necessary to satisfy TSSR 4.3.4.1.2. The basis, as stated in the LER, was that the LFMG trip on high reactor pressure did not affect the transients, since during the ATWS the peak reactor pressure and peak cladding temperature would have occurred before the 25-second time delay would have caused the LFMG to trip.

The inspectors discussed the testing requirements and UFSAR description with members of NMPC's engineering, technical support, and licensing groups. The discussions also focused on how the licensee reached their incorrect conclusion in 1996 that the testing was not required. The inspectors determined that the conclusion was based on a non-conservative interpretation of the UFSAR.

The inspectors, with members of the Unit 2 system engineering staff, reviewed the applicable procedures and plant drawings and verified that the revised surveillance test adequately tested the time delay and the LFMG trip. The inspectors noted that although the licensee recorded the actual time delay observed during the test, they did not provide an acceptable range of values. Through discussions with the Engineering Manager, the inspectors ascertained that, based on an engineering determination, the times obtained were acceptable. The inspectors also discussed with the Maintenance and Engineering Managers, the failure to specify an acceptable range. They agreed that the failure to specify acceptable values was a poor practice; a DER was written to review this further. The inspectors considered the failure to specify an acceptability range for the LFMG time delay as a weakness in the procedure and in the review of the associated procedure change.

The inspectors verified that the LER was completed in accordance with the requirements of 10 CFR 50.73. Specifically, the description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

c. Conclusion

NMPC identified that a portion of the Unit 2 testing for the recirculation pump trip in response to an anticipated transient without scram was not completed in accordance with the technical specifications. (NCV) Specifically, the logic system functional testing failed to include the high reactor pressure trip of the low frequency motor generator. In addition, the failure to specify an acceptability range for the LFMG time delay in the subsequent procedure change procedure indicated weaknesses in the procedure and in the review of the associated procedure change. Furthermore, in December 1996, NMPC missed an opportunity to identify the inadequate surveillance test due to a non-conservative interpretation of the UFSAR.

E8.5 (Closed) VIO 50-220/96-07-03: UFSAR Drawing Changed Without Performing a 10 CFR 50.59 Safety Evaluation

The inspectors performed an in-office review of the licensee response to an inadequate 10 CFR 50.59 safety evaluation for a proposed revision to the Unit 1 UFSAR service water system drawing. The preliminary safety evaluation incorrectly concluded that the UFSAR was unaffected. Therefore, no safety evaluation was performed. The licensee's root cause and corrective actions for the violation, as stated in their November 1996 response to the NRC, were appropriate. NMPC conducted a random sample review of preliminary safety evaluations generated between 1990 and 1994 to determine the potential scope of the issue. The inspectors determined that the licensee's review was thorough. The inspectors considered the actions to prevent recurrence to be adequate. Based upon the inspectors' review, the violation is closed.

E8.6 (Closed) 10 CFR 21 Notification: Potentially Defective Diesel Generator Air Start Solenoid Valves

a. Inspection Scope

The inspectors reviewed the details associated with the 10 CFR 21 (Part 21) notification regarding potentially defective Graham-White air start solenoid valves for EMD EDGs, and NMPC's evaluation for applicability to both units. The inspectors reviewed the applicable DER for each unit and discussed the related issues with members of NMPC's engineering staff.

b. Observations and Findings

On January 22, 1998, Engine Systems, Inc. (ESI) issued a Part 21 notification (SC 97-04) pertaining to possibly defective air start solenoid valves used with EMD EDGs. Specifically, in 1990 the valves were modified with a larger internal spring to reduce air leakage past the valves. However, ESI recently determined that with the increased spring size, the valves may not operate satisfactorily with a combined low air system pressure (<200 pounds per square inch gage (psig)) and low solenoid coil voltage (<105 volts direct current (Vdc)). ESI recommended that (1) if the minimum coil terminal voltage could not be maintained, then the internal spring should be replaced with an appropriately-sized spring, and (2) if the valve springs were not replaced, then the licensee should test an installed or spare solenoid valve to verify proper operation at the site specific minimum air pressure and voltage.

NMPC reviewed the Part 21 and identified that both Unit 1 EDGs and the Unit 2 Division III (high pressure core injection system) EDG contained the suspect valves. At Unit 1, the licensee determined that the worst-case condition would be a system air pressure of 191 psig combined with a solenoid coil terminal voltage of 100.2 Vdc. This worst case voltage was based on end-of-life battery conditions. NMPC determined that for a minimum system air pressure of 191 psig, a coil voltage of 107 Vdc would be sufficient to ensure proper valve operation. Since both Unit 1

station batteries were replaced in the Spring 1997, NMPC recalculated coil terminal voltage using an appropriate aging factor for the current condition of the installed batteries, and concluded that coil terminal voltages were adequate to ensure valve operability. However, this evaluation only provided a short-term justification, and based on discussion with the EDG system engineer, NMPC intends to replace the valves in the near future.

At Unit 2, the worst case condition would be 215 psig system air pressure combined with approximately 109 Vdc at the solenoid coil. Therefore, system air pressure and voltage were adequate to ensure operability of the installed valves. However, based on discussions with the EDG system engineer, NMPC was evaluating whether to replace the valves in May 1998, during the refueling outage, or complete the testing as recommended by ESI in the Part 21.

The inspectors reviewed the Part 21, and considered the licensee's actions to address the concern at each unit to be timely and technically sound. Therefore, this Part 21 is closed.

c. Conclusion

The licensee's actions at both units to address an industry concern with potentially defective emergency diesel generator air start solenoid valves was timely and technically sound.

E8.7 (Opened) 10 CFR 21 Notification: Potentially Defective GE SBM-Type Switches -- Unit 1

a. Inspection Scope

NMPC initiated a DER as a result of a General Electric Nuclear Energy (GENE) issued Part 21 notification of a possible adverse condition related to the spring-return function of some GE-provided control switches that could damage the associated control circuits. The inspectors reviewed the Part 21, the DER, and the related operating procedures, and discussed the issue with control room personnel.

b. Observations and Findings

On January 27, 1998, GENE issued a Part 21 notification informing licensees of a possible failure of certain GE SBM-type control switches having a spring-return feature and which were manufactured after March 1996. The switches were manufactured as a commercial grade item by another division of GE; GENE then dedicated the switches and supplied them to nuclear power plants as a basic component for safety-related applications. In early January 1998, GENE was notified by another licensee of a failure of one of the switches to automatically spring return to the normal position; subsequently, GENE was notified of several other failures. GENE determined that the most probable failure mode was mechanical binding internal to the switch. The Part 21 listed two safety concerns: (1) possible damage to the control circuitry, and (2) the possibility that the control

circuits would not be able to perform the safety function due to the failure to reset to the normal position.

NMPC identified that seven GE SBM-type switches manufactured after March 1996 were installed in safety-related functions in Unit 1: control switches for the EC condenser vent-to-torus blocking valves; containment spray bypass-to-torus blocking valves; and the containment spray test-to-torus flow control valve. NMPC engineering initiated DER 1-98-0202 to resolve this concern.

The inspectors reviewed the DER and Part 21 notification, and discussed the issue with the maintenance engineer responsible for the disposition. In addition, the inspectors discussed the potential failure mechanism with Unit 1 control room operators; all operators interviewed were knowledgeable of the need to ensure that the switches were returned to the normal position. The inspectors also reviewed the affected procedures. Neither Procedure N1-OP-13, "Emergency Cooling System" or Procedure N1-OP-14, "Containment Spray System" contained a precautionary note about the possible failure of the spring return switches. This was discussed with the ASSS, who stated that he would discuss the development of a temporary procedure change with his management. The NRC will review the DER disposition upon completion. This will be tracked as an open Part 21 item.

c. <u>Conclusion</u>

NMPC responded quickly and appropriately to a vendor notification related to a possible failure of spring-return switches used in the emergency cooling and containment spray systems at Unit 1. Control room operators were aware of the potential failure mode; however, the associated operating procedures had not been revised to include a precautionary note related to the concern.

E8.8 <u>(Closed) URI 50-220/96-05-03: Lack of 10CFR50.59 Safety Evaluation for the Modification to Restore the Unit 1 Blowout Panels to Compliance with UFSAR</u>

During the NRC Special Inspection 50-220/96-05 regarding the Unit 1 reactor and turbine building blowout panels being outside the design basis, an apparent violation was identified regarding the lack of 10 CFR 50.59 safety evaluation for the March 1995 modification to restore the blowout panel relief pressures to compliance with the UFSAR. Following the enforcement conference, the NRC reclassified this issue as an unresolved item pending additional NRC review, as documented in the letter from the NRC to NMPC dated June 18, 1996.

Prior to March 1995, the reactor and turbine building blowout panels were fastened with shear bolts larger than those specified on plant drawings causing the relief pressure to be greater than that described in the UFSAR. In March 1995, NMPC modified the blowout panels by removing every other shear bolt, which was intended to restore the relief pressure to that stated within the UFSAR. The particular concern described in NRC IR 50-220/96-05 was that, although the UFSAR did not explicitly describe the size or spacing of the blowout panel bolting, the change did alter the blowout panel design. Therefore, it should have required a

10 CFR 50.59 safety evaluation.

Following discussions with NRR, it was concluded that this modification did not change the system design as described in the UFSAR, nor did it involve a change to the TS; therefore, the modification to restore the blowout panels to the pressure stated in the UFSAR did not need a 10 CFR 50.59 safety evaluation. The inspectors had no further questions, and this item is closed.

E8.9 <u>(Closed) Unit 2 Special Report: Division I Standby EDG Non-valid Test and Non-valid Failure</u>

On January 8, 1998, the Division I EDG tripped on overspeed during a monthly surveillance test. Subsequently, the licensee verified that an actual overspeed condition did not occur, and that a fault in the test mode circuitry caused the trip. Particularly, the optical isolator transmitter board and associated receiver board in the secondary start circuitry failed due to thermal aging. The failed circuitry provided a repeater signal to trip the EDG in an overspeed condition; however, this signal was only utilized in the test mode and is bypassed during the emergency mode. The isolator was replaced and the EDG was re-tested successfully. The isolator failure was documented in DER 2-98-0033, and NMPC began evaluating the need to replace additional isolators, as part of the DER review.

As required by TS 4.8.1.1.3, NMPC documented the EDG failure in a special report to the NRC (NMPC letter NMP2L 1749 dated February 5, 1998). As documented in that report, NMPC determined that the test was non-valid based on the guidance provided in NRC Regulatory Guide (RG) 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," because the trip was initiated from a portion of circuitry bypassed in the emergency mode. The inspectors reviewed the applicable plant drawings and confirmed that the trip would not have occurred in the emergency mode. The inspectors' review of the failure, and the guidance provided in RG 1.108, indicates that NMPC appropriately determined that the failure and test were non-valid.

E8.10 <u>Administrative Closure of Escalated Enforcement Items</u>

The escalated enforcement items (EEIs) listed below are being administratively closed, due to the issuance of the indicated enforcement action (EA) letter and associated determination:

EEI 50-410/96-15-02:	closed by EA 96-475, VIO 3013
EEI 50-410/96-16-01:	closed by EA 96-494, VIO 3043
EEI 50-410/96-16-02:	closed by EA 96-494, VIO 3043
EEI 50-410/96-16-03:	closed by EA 96-494, VIO 2023
EEI 50-410/96-16-04:	closed by EA 96-494, VIO 2013
EEI 50-410/96-16-05:	closed by EA 96-494, VIO 3023
EEI 50-410/96-16-06:	closed by EA 96-494, withdrawn
EEI 50-410/96-16-10:	closed by EA 96-494, VIO 3033

In addition, two of the EEIs were classified as non-cited violations (NCVs) in the EA letter; as such, these NCVs are being assigned tracking numbers in this inspection report:

EEI 50-410/96-16-07:	closed by EA 96-494, NCV 50-410/98-01-10
EEI 50-410/96-16-08:	closed by EA 96-494, NCV 50-410/98-01-11

IV. PLANT SUPPORT

Using NRC Inspection Procedure 71750, the resident inspectors routinely monitored the performance of activities related to the areas of radiological controls, chemistry, emergency preparedness, security, and fire protection. Minor deficiencies were discussed with the responsible management, and significant observations are detailed below.

R1 Radiological Protection and Chemistry Controls (71750)

R1.1 <u>Potentially Contaminated Truck Released from Unit 1</u>

On February 9, 1998, NMPC was notified that radiation levels on an empty flat-bed trailer, released from Unit 1 on February 7, 1998, may have exceeded levels specified in 49 CFR, Part 173.443(c). The trailer was placed in a secure area on Babcock and Wilcox's property in Parks Township, Pennsylvania to await further surveys and evaluation. This is characterized as an unresolved item pending further surveys and review of the results by NRC. **(URI 50-220/98-01-12)**

R8 Miscellaneous RP&C Issues (71750)

R8.1 <u>Administrative Closure of Escalated Enforcement Items</u>

The escalated enforcement items (EEIs) listed below are being administratively closed, due to the issuance of the indicated enforcement action (EA) letter and associated determination:

EEI 50-220/97-07-07:	closed by EA 97-530, VIO 1013
EEI 50-220/97-07-09:	closed by EA 97-530, VIOs 1033 & 1034
EEI 50-220 & 50-410/97-07-10:	closed by EA 97-530, VIO 1023
EEI 50-220 & 50-410/97-07-12:	closed by EA 97-530, withdrawn

In addition, two of the EEIs were classified as non-cited violations (NCVs) in the EA letter; as such, these NCVs are being assigned tracking numbers in this inspection report:

EEI 50-220 & 50-410/97-07-06:	closed by EA 97-530, NCV 50-220 & 50-410/98-01-13
EEI 50-220 & 50-410/97-07-11:	closed by EA 97-530, NCV 50-220 & 50-410/98-01-14

F2 Status of Fire Protection Facilities and Equipment (71750)

F2.1 Unit 1 Unplanned Fire Alarms and Preaction Sprinkler System Actuation

a. Inspection Scope

The inspectors reviewed the circumstances surrounding unplanned fire alarms and preaction sprinkler system actuation at Unit 1. The inspectors evaluated control room and fire brigade response to the event, and discussed the issue with fire protection supervision.

b. Observations and Findings

On January 8, 1997, multiple fire alarms were indicated in the Unit 1 control room originating from local fire panels (LFPs) 3, 4, and 5 in the Unit 1 turbine building (TB). Control room staff announced the alarms and investigation by the fire brigade identified that a LFP-3 detection zone was in an alarm condition and that a preaction sprinkler system had initiated on TB 261′ [261-foot] elevation. Subsequently, wet pipe sprinkler system water flow alarms were received on LFPs 3, 4 and 5 for the offgas building, TB 291′ elevation, and TB 351′ elevation, respectively.

The inspectors observed licensee actions from both the Unit 1 control room and in the TB. The fire brigade confirmed that no fire existed, and that no water had actually been discharged to the TB. Due to inclement weather (rain and high winds), numerous roof leaks had been detected during the day, and the licensee identified water in an area adjacent to a fire detector located in TB 261′. Subsequent licensee investigation concluded that water intrusion into this detector resulted in the initial preaction sprinkler system alarm on LFP-3. Additionally, the licensee presumed that the false indication of the wet pipe system water flow alarms was caused by a backup of the sprinkler system drain header, since water had overflowed the air gap funnel drain cups associated with the wet pipe sprinkler system on TB 261′ and TB 277′. The inspectors observed that both control room and fire brigade personnel responded appropriately to the event and the investigation effort was adequately coordinated.

Through discussions with the fire protection supervisor, previous similar occurrences were attributed to limited drainage on the wet pipe system common drain header, and that the water overflow on TB 277′ was likely a result of system backpressure. The system had design features, including retard chambers and check valves, to minimize the impact of system backpressure perturbations producing erroneous alarms. However, the fire protection supervisor stated that erroneous alarms sometimes occurred, even during routine surveillance testing. System backpressure, concurrent with check valve leakage, could result in pressure switch actuations and provide false indications of wet pipe system flow on TB 261′ and TB 291′ elevations. The inspectors considered that the failure to fully investigate and resolve previous similar occurrences was a weakness and likely contributed to the recent event.

The licensee issued a DER 1-98-0040 to document the issue, and several Problem Identification (PID) entries were made to address 1) the potential poor system drainage, 2) the roof leakage, and 3) check valve seat leakage. The inspectors walked down the affected fire protection systems with the fire protection supervisor. The system configuration appeared to support the licensee's conclusion for actuation of the wet pipe system flow indications. The licensee replaced a check valve located on TB 261', and the inspectors observed that the check valve body and seat revealed significant wear and corrosion, and the valve disc was degraded. Subsequent discussion with the supervisor indicated that further corrective action included replacement of similar-type check valves within the wet pipe system to preclude the backpressure spikes. The inspectors considered licensee corrective actions to be appropriate. Although the inspectors did not consider fire protection system operability to be affected by the degraded components, the impact of the deficiencies could hinder plant personnel responding to an in-plant fire due to potential multiple false alarms.

c. <u>Conclusions</u>

Control room and fire brigade personnel appropriately responded to numerous Unit 1 fire alarm actuations, and the investigation effort appeared adequately coordinated. The failure to fully investigate and resolve previous similar false fire protection system actuations was a weakness and likely contributed to the recent event. Although Unit 1 fire suppression system operability did not appear to be affected by degraded components, the impact of the deficiencies could hinder plant personnel responding to an in-plant fire due to potential multiple false alarms.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection.

The final exit meeting occurred on March 6, 1998. During this meeting, the resident inspector findings were presented. NMPC did not dispute any of the findings or conclusions. Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

R. Abbott	Plant Manager, Unit 1 (Acting)
D. Barcomb	Manager, Unit 2 Radiation Protection
D. Bosnic	Manager, Unit 2 Operations
J. Burton	Manager, Quality Assurance
H. Christensen	Manager, Security
J. Conway	Vice President, Nuclear Engineering
G. Correll	Manager, Unit 1 Chemistry
R. Dean	Manager, Unit 2 Engineering
A. DeGracia	Manager, Unit 1 Work Control
S. Doty	Manager, Unit 1 Maintenance
K. Dahlberg	Plant Manager, Unit 2 (Acting)
G. Helker	Manager, Unit 2 Work Control
A. Julka	Director, ISEG
P. Mazzafero	Manager, Unit 1 Technical Support
L. Pisano	Manager, Unit 2 Maintenance
R. Randall	Manager, Unit 1 Engineering
V. Schuman	Manager, Unit 1 Radiation Protection
R. Smith	Manager, Unit 1 Operations
R. Tessier	Manager, Training
C. Terry	Vice President, Nuclear Safety Assessment & Support
C. Ware	Manager, Unit 2 Chemistry
K. Ward	Manager, Unit 2 Technical Support
D. Wolniak	Manager, Licensing

INSPECTION PROCEDURES USED

IP 36100	10 CFR Part 21 Inspections at Nuclear Power Plants
IP 37551	On-Site Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71714	Cold Weather Preparations
IP 71715	Sustained Control Room and Plant Observation
IP 71750	Plant Support
IP 90712	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering
IP 92904	Followup - Plant Support

Attachment 1

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/98-01-01	NCV	Inadequate Separation Between Conduits for Safety-Related Temperature Elements
50-220/98-01-02	NCV	Failure to Perform Required Engineering Evaluations on Longstanding Catch Containments
50-220/98-01-03	VIO	Liquid Poison System Surveillance Testing Inadequacy
50-220/98-01-04	NCV	Service Water Valve Maintenance Violated Secondary Containment
50-220/98-01-05	NCV	Failure to Perform a Design Change for a Permanently Installed Scaffold
50-220/98-01-06	VIO	Failure to Perform an Engineering Safety Analysis for Inoperable CREVS TCV -- Failed Since 1992
50-410/98-01-07	NCV	Switchgear Inoperable due to Racked Out Circuit Breakers
50-410/98-01-08	NCV	Failure to Report an Unanalyzed Condition
50-410/98-01-09	NCV	Failure to Perform LSFT of the ATWS-RPT LFMG Trip on High Pressure
50-410/98-01-10	NCV	Administrative Closure of EEI 50-410/96-16-07
50-410/98-01-11	NCV	Administrative Closure of EEI 50-410/96-16-08
50-220/98-01-12	URI	Potentially Contaminated Truck Released Offsite
50-220 & 50-410/98-01-13	NCV	Administrative Closure of EEI 50-220 & 50-410/97-07-06
50-220 & 50-410/98-01-14	NCV	Administrative Closure of EEI 50-220 & 50-410/97-07-11
----	Part 21	GE SBM-Type Switches

CLOSED

50-220/96-12-01	EEI	Failure to Include Six SSCs in the Scope of the Maintenance Rule
50-220/96-12-05	EEI	Ineffective Goals and Monitoring for (a)(1) SSCs
50-410/96-15-02	EEI	Failure to Check MOV Pressure Locking Calculations
50-410/96-16-01	EEI	Control Room Chiller Deficiencies for SW Setpoints
50-410/96-16-02	EEI	Control Room Chillers Inoperable due to SW Setpoints

Attachment 1

50-410/96-16-03	EEI	Failure to Repair Control Room Chillers After Previous Trips
50-410/96-16-04	EEI	RCIC Lube Oil PCV Failed Open Since 1991
50-410/96-16-05	EEI	RCIC Design Calculations Incorrect and No Independent Review
50-410/96-16-07	EEI	No Safety Evaluation Performed for RCIC PCV Failed Open
50-410/96-16-08	EEI	UFSAR Not Updated When New Design for RCIC PCV Installed
50-410/96-16-10	EEI	Design Errors Related to RCIC
50-220 & 50-410/97-07-06	EEI	Failure to Update PCPs
50-220/97-07-07	EEI	Radwaste Shipment Exceeded 49 CFR Limits
50-220/97-07-09	EEI	Radwaste Shipments to Wrong Address
50-220 & 50-410/97-07-10	EEI	Radwaste Shipment of Wrong Liner
50-220 & 50-410/97-07-11	EEI	Failure to Identify and Correct Problems with PCPs
50-410/98-01-01	NCV	Inadequate Separation Between Conduits for Safety-Related Temperature Elements
50-410/98-01-02	NCV	Failure to Perform Required Engineering Evaluations on Longstanding Catch Containments
50-220/98-01-04	NCV	Service Water Valve Maintenance Violated Secondary Containment
50-220/98-01-05	NCV	Failure to Perform a Design Change for a Permanently Installed Scaffold
50-410/98-01-07	NCV	Violation of TSs -- Switchgear Inoperable due to Racked Out Circuit Breakers
50-410/98-01-08	NCV	Failure to Report an Unanalyzed Condition
50-410/98-01-09	NCV	Violation of TSs -- Failure to Perform LSFT of the ATWS-RPT LFMG Trip on High Pressure
50-410/98-01-10	NCV	Administrative closure of EEI 50-410/96-16-07
50-410/98-01-11	NCV	Administrative closure of EEI 50-410/96-16-08
50-220 & 50-410/98-01-13	NCV	Administrative closure of EEI 50-220 & 50-410/97-07-06
50-220 & 50-410/98-01-14	NCV	Administrative closure of EEI 50-220 & 50-410/97-07-11

----	Part 21	Potentially Defective Diesel Generator Air Start Solenoid Valves
50-410/97-05-01	LER	HPCS System Inoperable Due to Failed Unit Cooler
50-220/97-10-01	LER	TS Required Shutdown Due to EC Condenser Tube Leak
50-410/97-13	LER	Prior to 1992, Emergency Switchgear Not Seismically Qualified with Breakers Racked Out
50-410/97-16	LER	Missed TSSR 4.3.4.1.2 for ATWS-RPT Trip of LFMG
50-410/98-01	LER	Entry Into TS 3.0.3 Due to Containment Atmospheric Gaseous/Particulate Radiation Monitors Inoperable
50-410/98-02	LER	Violation of TS 6.2.2.b - No Licensed Operator At-the-Controls
50-220/96-07-03	VIO	UFSAR Drawing Changed Without Performing a 10CFR50.59 Safety Evaluation
50-220/96-05-03	URI	Lack of 10 CFR 50.59 Safety Evaluation for the Modification to Restore the Unit 1 Blowout Panels to Compliance with UFSAR

WITHDRAWN

50-220/96-12-06	EEI	Unacceptable Performance Criteria to Verify Preventive Maintenance was Effective
50-220/96-12-07	EEI	Ineffective Monitoring and Untimely Evaluation of (a)(2) SSCs
50-410/96-16-06	EEI	RCIC Inoperable Since 1991
50-220 & 50-410/97-07-12	EEI	Failure to Conduct Audits of Vendors Supplying Shipping Casks

UPDATED

None

LIST OF ACRONYMS USED

AC	Alternating Current
ASSS	Assistant Station Shift Supervisor
ATWS-RPT	Anticipated Transient Without Scram - Reactor Pump Trip
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CMS	Containment Monitoring System
CREVS	Control Room Emergency Ventilation System
CSO	Chief Station Operator
DER	Deviation/Event Report

Attachment 1

EA	Enforcement Action
EC	Emergency Cooling
EDG	Emergency Diesel Generator
EEI	Escalated Enforcement Item
ESA	Engineering Supporting Analysis
ESF	Engineered Safeguards Feature
ESI	Engine Systems, Inc.
FRI	Fuel Reliability Index
GE	General Electric
HPCS	High Pressure Core Spray
IN	Information Notice
IR	Inspection Report
IST	Inservice Testing
ITS	Improved Technical Specifications
kV	kiloVolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LFMG	Low Frequency Motor Generator
LSFT	Logic System Functional Testing
μCi/sec	microCuries per second
MOV	Motor-Operated Valve
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NOED	Notice of Enforcement Discretion
NRC	Nuclear Regulatory Commission
Part 21	Title 10 of the Code of Federal Regulations Part 21
PCP	Process Control Program
PCV	Pressure Control Valve
PDR	Public Document Room
psig	pounds per square inch gage
RBCLC	Reactor Building Closed Loop Cooling
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RG	Regulatory Guide
RHR	Residual Heat Removal
RO	Reactor Operator
SE	Safety Evaluation
SORC	Station Operating Review Committee
SRO	Senior Reactor Operator
SSC	Structure, System, and Component
SSS	Station Shift Supervisor
STA	Shift Technical Advisor
SW	Service Water
TB	Turbine Building
TBCLC	Turbine Building Closed Loop Cooling
TCV	Temperature Control Valve

Attachment 1

TS	Technical Specification
TSSR	Technical Specification Surveillance Requirement
UFSAR	Updated Final Safety Analysis Report
Unit 1	Nine Mile Point Unit 1
Unit 2	Nine Mile Point Unit 2
URI	Unresolved Item
Vdc	volts direct current
VIO	Violation
WO	Work Order
YHO	Yellow Holdout