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
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/98-19 & 50-410/98-19
November 22, 1998 - January 2, 1999

This integrated inspection report includes aspects of licensee operations, engineering, maintenance, and plant support. The report covered a six-week period of resident inspection and the results of an emergency preparedness inspection from December 7 to 11, 1998, by a region based specialist.

Operations

On November 24, 1998, Unit 2 was shutdown to troubleshoot and repair the reactor recirculation system flow control valve. During the plant shutdown and subsequent startup, the operators' performance was generally good as evidenced by clear three-way communications, appropriate use of procedures and sufficient management oversight and control. (Section O1.4)

On December 30, 1998, a control rod inadvertently inserted as a result of a failed component associated with the control rod drive system. Unit 2 operators responded very well to the abnormal combination of alarms that were received and took conservative actions. Good communication between operators and good management oversight were noted. (Section O1.5)

A good focus on shutdown risk was evident during the Unit 2 forced outage to repair the reactor recirculation system flow control valve. (Section O2.1)

On November 23, 1998, Unit 2 failed to complete the required technical specification surveillance tests for source range monitors and intermediate range monitors during a plant shutdown. Sufficient controls were not in place to ensure that requirements were met; specifically the shutdown procedure was weak. This licensee-identified and corrected non-compliance is being treated as a Non-Cited Violation. **(NCV 50-410/98-19-01)** (Section O8.2)

Maintenance

During routine observations of surveillance testing at Unit 2, two surveillance test procedures were determined to be weak in that specific procedure steps lacked clarity. Personnel were capable of completing the procedures; however, there was the potential to misunderstand what the required actions were. (Section M3.1)

Engineering

Activities associated with the reactor coolant system flow control valve failure cause determination and repair were acceptable and technically sound. However, previous actions to address the flow control valve degradation were not effective in preventing recurring problems. (Section E.1.1)

Executive Summary (cont'd)

An inadequate review associated with the Unit 2 depleted zinc oxide injection modification, installed in June 1998, resulted in an unexpected rise in reactor vessel water level during the November 30, 1998, plant startup. This licensee identified and corrective violation of design control was treated as a non-cited violation. **(NCV 50-410/98-19-02)** The Unit 2 review of the unexpected rise in reactor vessel water level was technically sound and NMPC appropriately revised the operating procedures to prevent recurrence. However, a weakness was noted with the documentation of corrective action in the deviation/event report in that the evaluation did not include the ongoing evaluation of the modification process. (Section E1.2)

Niagara Mohawk Power Corporation demonstrated a good questioning attitude when they identified that the weight of 522 safety-related valves at Unit 2 was greater than the weight shown on the vendor valve drawings. Following a comprehensive and thorough evaluation, NMPC determined that a total of five valves within residual heat removal, reactor core isolation cooling and reactor building floor drain systems caused the associated piping not to meet design requirements under all conditions **(NCV 50-220/98-19-04)** (Section E8.6).

Niagara Mohawk Power Corporation demonstrated a good questioning attitude during their Generic Letter 96-01 review by identifying an unrelated discrepancy associated with three motor-operated valves within the Unit 2 reactor core isolation cooling (RCIC) system. Specifically, the seal-in contacts within the control circuits of these valves were in series with overload relay contacts. Should the overload relays trip in conjunction with a transitory RCIC initiation signal, the seal-in function would have been lost, rendering the system incapable of performing the design function. This discrepancy existed from initial plant startup until it was unknowingly corrected by an unrelated modification in December 1993 **(NCV 50-410/98-19-05)** (Section E8.7).

<u>Plant Support</u>

Emergency preparedness equipment surveillances and communication tests were performed as required and the facilities and equipment were determined to be in a good state of operational readiness. A review of the emergency preparedness procedure change review process, and a sampling of recent changes, indicated that a good change control program was being implemented. The emergency response organization (ERO) training program was well implemented in that ERO members' qualifications were current and drills were conducted as required. (Sections P.2, P.3 and P.5)

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ATTACHMENTS

Attachment 1 - Partial List of NMPC Persons Contacted
- Inspection Procedures Used
- Items Opened, Closed, and Updated
- List of Acronyms Used

Report Details

Summary of Plant Status

With the exception of routine scheduled power reductions, Unit 1 operated at 100% reactor power throughout the inspection period.

Unit 2 began the inspection period in single loop at a reduced power level of 35% due to a problem with a flow control valve. On November 23, operators prepared to restart the "B" recirculation pump. When the switch was positioned to start, the recirculation flow control valve immediately traveled from 17% open to 10% open and then slowly drifted closed. NMPC elected to shutdown the unit to identify and repair the problem and on November 24, the plant was shutdown. Technicians found that a recirculation flow control valve component had failed. Repairs were made, and on November 30, the reactor was critical. The plant was returned to full power on December 6 and remained there through the end of the inspection period.

I. Operations

O1 Conduct of Operations [1]

O1.1 General Comments (71707)

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations. The reviews included tours of accessible 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 (TS), and verification that logs and records accurately identified equipment status or deficiencies. In general, the conduct of operations was professional and safety-conscious.

O1.2 Plant Shutdown for Reactor Recirculation System Flow Control Valve Repair (Unit 2)

a. Inspection Scope (71707)

NMPC (Niagara Mohawk Power Corporation) operators shutdown Unit 2 on November 24, 1998, following an unsuccessful attempt to recover the "B" reactor recirculation loop. The inspectors assessed NMPC performance during the shutdown. The assessment included control room observations, and review of procedures, operators' logs, and Deviation/Event Reports (DERs) associated with the shutdown.

b. Observations and Findings

On November 13, 1998, the "B" reactor recirculation system (RCS) flow control valve (FCV) failed closed, and the "B" RCS loop was removed from service. On November 23, following repairs to the system, NMPC attempted to recovery the loop. However, during

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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 that was used as inspection guidance is listed for each applicable report section.

the recovery attempt, the FCV did not operate properly. As a result, NMPC management directed the operators to shutdown the unit for further troubleshooting of the FCV.

During the preparations to shutdown the plant, operators manually tripped the main turbine due to an increase in vibration resulting from an imbalance in supply pressure between the "A" and "B" moisture separator reheaters (MSR) caused by the main steam supply isolation valve to the "B" MSR failing to close completely. At 10:01 a.m. on November 24, the operators completed the reactor shutdown by placing the mode switch in shutdown, effectively scramming the plant from 13.8% power in accordance with plant operating practices.

The inspectors observed portions of the plant shutdown from the control room and considered the operators' performance to be generally good. During the pre-shutdown shift brief, the operators asked detailed questions which indicated a good understanding of plant conditions and scheduled evolutions. During the shutdown, particularly immediately following the scram, operators' performance was considered good, as evidenced by deliberate direction provided by the Assistant Station Shift Supervisor (ASSS), clear three-way communications between the operators, appropriate use of procedures and sufficient management oversight of the shutdown activities.

Subsequent to entering Mode 3, hot shutdown, NMPC identified that the technical specification (TS) channel functional tests (CFTs) of the source range monitors (SRMs) and intermediate range monitors (IRMs) were not completed. This issue is described in Section O8.2 of this report.

O1.3 Plant Startup Following Forced Outage for Reactor Recirculation System Flow Control Valve Repair (Unit 2)

a. Inspection Scope (71707)

On November 30, 1998, NMPC operators performed a reactor startup of Unit 2. The inspectors assessed NMPC performance during the startup. The assessment included control room observations, and procedure, operator logs and DER reviews.

b. Observations and Findings

The operators' performance during the startup was generally good as evidenced by the inspectors observations of clear three-way communications between the operators, appropriate use of procedures and sufficient management oversight and control of the startup activities. In addition, the operators responded appropriately to various challenges during the startup, including difficulties controlling reactor vessel water level, and an inadvertent isolation of the reactor core isolation cooling (RCIC) and shutdown cooling (SDC) systems. The details associated with these issues are described in Sections E1.2 and O8.3 respectively.

O1.4 Conclusions on Plant Operations (Unit 2) (71707)

On November 24, 1998, Unit 2 was shutdown to troubleshoot and repair the reactor recirculation system flow control valve. During the plant shutdown and subsequent startup, the operators' performance was generally good as evidenced by clear three-way communications, appropriate use of procedures and sufficient management oversight and control.

O1.5 Control Rod Drift (Unit 2)

a. Inspection Scope (71707, 93702))

On December 30, 1998, with Unit 2 at 100% power, operators received a rod drive control system inoperable alarm and a control rod drift alarm. The operators determined that control rod 18-43 had inserted from position 48 to position 26. The inspector observed the operator's actions from the control room to evaluate their response to the transient and reviewed the alarm response procedures and special operating procedures that were used. Additionally, the inspector verified that the technical specification requirements had been met and that the control rod was disabled.

b. Observations and Findings

On December 30, 1998, control rod 18-43 inserted from position 48 to position 26. Operators responded appropriately and reduced power to 90% and subsequently lowered it to 75%. Based on the unknown failure mechanism of the control rod, the operators declared the control rod inoperable. Technical specifications require that an inoperable control rod be inserted and disabled within one hour. However, because the rod drive control system was "locked-up," and would not respond, the operators could not insert the control rod. Following review by the reactor analyst, and after stationing extra personnel, the operators individually scrammed control rod 18-43 at the hydraulic control unit (HCU), and immobilized it per the technical specifications. Reactor power was then raised to 85% in accordance with operating procedures.

The inspector noted good three way communication between operators, and very good support from off-shift licensed and non-licensed personnel. Involvement of senior plant management was noted, in addition to support from other senior reactor operators. The operators maintained appropriate safety focus and promptly notified other station personnel to assist in resolving the problem.

NMPC determined that the cause of the rod drive control system failure and subsequent rod drift was the result of a failed transponder card in the HCU for control rod 18-43. Prior to restoring the control rod to an operable status, NMPC's technical support department was required to disposition the deviation/event report (DER) associated with the event. Technical support determined that the system lock-up was the result of faulty diode in transponder card 18-43. The diode failed causing the insert supply directional control valve to energize and thus caused the control rod to inadvertently insert. NMPC determine that a similar event occurred in December, 1993 and that the failure was normal aging/fatigue of the component. Technical support and instrument and controls personnel

were available and utilizing station corrective maintenance work controls, replaced the transponder card.

c. Conclusions

On December 30, 1998, a control rod inadvertently inserted as a result of a failed component associated with the control rod drive system. Unit 2 operators responded very well to the abnormal combination of alarms that were received and took conservative actions. Good communication between operators and good management oversight were noted.

O2 Operational Status of Facilities and Equipment

O2.1 Forced Outage for Reactor Recirculation System Flow Control Valve Repairs (Unit 2)

a. Inspection Scope (71707)

During the Unit 2 forced outage to repair the reactor recirculation system FCV, the inspectors attended NMPC's meetings and reviewed outage related documentation, particularly work plans, shut down risk evaluations and outage related DERs. Also, the inspectors, accompanied by NMPC personnel, toured accessible portions of the Unit 2 drywell.

b. Observations and Findings

The inspector observed appropriate communications between the various departments and the operations department, as evidenced by the operators' awareness of activities ongoing in the plant. Shiftly shut down risk evaluations were completed in accordance with the governing procedure. During a tour of the drywell, the inspectors found the material condition of the equipment, and the general housekeeping were good.

c. Conclusions

A good focus on shutdown risk was evident during the Unit 2 forced outage to repair the reactor recirculation system flow control valve.

O8 Miscellaneous Operations Issues (92700, 92901)

O8.1 (Closed) VIO 50-220/97-80-01 and 50-410/97-80-01: DERs extended without justification. The inspectors determined that numerous station DERs failed to contain justification for the extension of corrective action implementation, as required by NMPC procedures. Corrective actions included proper disposition or extension of the identified deficiencies, periodic reinforcement of management expectations at weekly meetings, and the conduct of periodic reviews of DER status. The long term corrective actions included the completion of a quality assurance audit, procedure changes, performance of semi-annual corrective action audits, and senior management team review of status during the quarterly trend review. The inspector reviewed the procedure change and discussed the trend reports with station personnel. The quarterly DER report program trend summary

indicated that the number of deficiencies identified with the DER process were declining. The senior management team has continued to review the exceptions on a bi-weekly basis and current status reports indicate a downward trend in the number of exceptions. In addition, NMPC changed the quality assurance audit checklist to include a review of the actual completion date in comparison to the scheduled completion date. The inspectors determined that the corrective actions were reasonable. The violation is closed.

O8.2 (Closed) LER 50-410/98-27: Missed Technical Specification Required Surveillance of SRMs and IRMs Prior to Mode Change

a. Inspection Scope (92903,62706)

During the plant shutdown on November 24, 1998, Unit 2 entered hot shutdown without performing the Channel Functional Tests on the SRMs and IRMs as required by technical specifications. The inspectors completed an on-site review of the LER and evaluated NMPC corrective actions and procedures. In addition, the inspectors attended the associated Station Operations Review Committee (SORC) meeting.

b. Observations and Findings

On November 23, operators lowered power in accordance with Procedure N2-OP-101D, "Power Changes," in preparation to recover the "B" RCS loop following the completion of troubleshooting and repairs. Upon recovery of the loop, NMPC intended to return the unit to full power, therefore, the steps to complete SRM and IRM testing were determined to not be required. However, when the operators started the "B" RCS pump, the associated FCV did not operate properly. As a result, NMPC management directed the operators to shutdown the unit for further troubleshooting of the FCV. Operators completed the shutdown in accordance with Procedure N2-OP-101C, "Plant Shutdown." However, the shutdown procedure did not contain a step to verify the completion of the TS-required surveillance for the SRMs and IRMs. As a result, the shutdown was performed without completing the TS-required surveillance testing of the SRMs and IRMs.

The SRMs and IRMS are required to be operable in hot shutdown; and channel functional tests are required to be completed monthly for the SRMs and weekly for the IRMS by TSs 4.3.7.6 and 4.3.1.1 respectively. TS 4.0.4 states that entry into an operational condition shall not be made unless the surveillance requirements associated with the limiting conditions for operation (LCOs) have been preformed within the applicable surveillance intervals. Therefore, the failure to complete the TS surveillance requirement for the SRMs and IRMs is a violation of TS 4.0.4. 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 50-410/98-19-01)**

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. 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. NMPC revised the applicable procedure to verify the SRM and IRM surveillances are properly performed. This LER is closed.

c. Conclusions

On November 23, 1998, Unit 2 failed to complete the required technical specification surveillance tests for source range monitors and intermediate range monitors during a plant shutdown. Sufficient controls were not in place to ensure that requirements were met; specifically the shutdown procedure was weak. This licensee-identified and corrected non-compliance is being treated as a Non-Cited Violation. **(NCV 50-410/98-19-01)**

O8.3 (Closed) LER 50-410/98-28: inadvertent isolation of RCIC [reactor core isolation cooling] and SDC [shutdown cooling] due to a spurious trip of a temperature switch. During power ascension following the forced outage, on December 2, 1998, Unit 2 experienced an isolation of the RCIC system and the SDC system received an isolation signal. The isolation occurred while a reactor operator (RO) was taking leak detection system area temperature readings in the control room. Specifically, the RO was reading the temperature associated with the trip unit designed to isolate the RCIC and SDC system in the event of a system leak.

RCIC and SDC systems responded as designed for an area temperature leak detection system isolation signal. The operators verified no system leakage occurred and confirmed that the temperature monitored by the trip unit was normal and below the trip setpoint. The appropriate TS were entered. The trip unit was replaced and the systems restored to operable condition. The inspectors observed various portions of the operators' response to the event and considered their actions to be appropriate.

The inspectors completed an on-site review of the issue. During the review, the inspectors evaluated the applicable DER and LER. In addition, the inspectors attended the associated SORC meeting. Based on the inspectors observations during the meeting, the SORC members demonstrated an appropriate focus on safety.

The apparent cause of the event was a spurious failure of the trip unit. However, NMPC could not duplicate the problem. Therefore, the trip unit was sent to an independent laboratory for further analysis. As stated in the LER, NMPC intends to supplement LER 50-410/98-28 upon completion of the analysis.

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. 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

M1 Conduct of Maintenance

M1.1 General Comments (61726, 62707)

Using NRC Inspection Procedures 61726 and 62707, the resident inspectors periodically observed various maintenance activities and surveillance tests. As part of the observations, the inspectors evaluated the activities with respect to the requirements of the Maintenance Rule, as detailed in 10CFR50.65. 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 98-13080-03 — reset average power range monitor/rod block monitor setpoints for two loop operation
- N1-ST-Q28 — Containment Spray Raw Water Intertie Check valve quarterly Operability Test
- N1-ST-Q1C — Core Spray Pump and Valve Operability Test
- N1-ST-M4 — Emergency Diesel Generator Operability Test
- N2-OSP-EGS-M@001 — Diesel Generator & Diesel Air Start Valve Operability Test-Division I and II
- N2-OSP-EGS-M@002 — Diesel Generator & Diesel Air Start Valve Operability Test-Division III
- N2-ESP-ENS-Q731 — Quarterly Channel Functional Test of LPCS/LPCI Pumps A, B, and C (Normal and Emergency Power) Auto Start Time Delay Relays

M3 Maintenance Procedures and Documentation

M3.1 Surveillance Test Procedures (Unit 2)

a. Inspection Scope (61726)

During the routine observations of Unit 2 surveillance activities, the inspectors reviewed various test procedures and compared the procedures with actual work practices to assess the quality and accuracy of the procedures.

b. Observations and Findings

During recent observations of surveillance testing at Unit 2, the inspectors identified shortcomings with two procedures. Specifically, N2-ESP-ENS-Q731, "Quarterly Channel Functional Test of LPCS [low pressure coolant spray]/LPCI [low pressure coolant injection] Pumps A, B, and C (Normal and Emergency Power) Auto Start Time Delay Relays," requires the technicians to confirm and record the position of the normal and alternate feeder breakers to the Division I and Division II emergency switchgear. In response to this

step the technicians are required to place a check-mark indicating whether the breaker is "open" or "closed". However, the practice at Unit 2 is to always have one of these breakers removed from their respective cubicle. During the performance of the test, the technicians placed a check-mark next to "open" for the empty cubical. Although this interpretation was appropriate for the test, the inspectors considered the procedure wording to be poor, since neither option accurately reflected plant conditions.

The second shortcoming was with N2-OSP-EGS-M@002, "Diesel Generator & Diesel Air Start Valve Operability Test - Division III." Specifically, Step 8.2.24 requires the operators to adjust volt-amperes reactive (VAR) to the desired loading. Based on discussion with several operators, and the system engineer, NMPC personnel were not sure what the desired loading should be. Following discussions with the system engineer, the inspectors concluded that although there was no minimum required VAR loading requirement for testing the emergency diesel generator (EDG), the words in the procedure were vague. Subsequent to the end of the inspection period, NMPC changed to the procedure to provide a specific VAR value based on the expected accident loading of the EDG. The inspectors considered this change to be appropriate.

c. Conclusion

During routine observations of surveillance testing at Unit 2, two surveillance test procedures were determined to be weak in that specific procedure steps lacked clarity. Personnel were capable of completing the procedures, however, there was the potential to misunderstand what the required actions were.

M8 Miscellaneous Maintenance Issues (92902, 92700, 90712)

M8.1 (Closed) URI 50-410/96-07-06: Inadequate restoration after maintenance/testing. The NRC identified a concern at Unit 2 regarding the restoration of system lineups following maintenance and surveillance activities. In particular, problems were noted as described in the following three Deviation/Event Reports (DERs):

- DER 2-94-1612 - a residual heat removal (RHR) pump minimum flow valve was inadvertently left shut following a surveillance test;
- DER 2-95-0237 - a RCIC isolation cooling system steam line drain pot level switch variable leg isolation valve was incorrectly left shut following repacking; and
- DER 2-95-1854 one train of suppression chamber spray was disabled due to failure to properly restore the correct valve line up following a leakage test.

This item was left unresolved to evaluate the issues described in the subject DERs, to determine whether the corrective actions taken to address each DER were appropriate, and to evaluate the adequacy of NMPC's controls for configuration restoration following maintenance or testing.

The inspectors completed an on-site review of the issues and corrective actions for the three DERs. The inspectors reviewed the procedures currently in-place regarding system

restoration following maintenance and surveillance activities and discussed the system restoration process with members of the Unit 2 staff. In addition, inspectors reviewed Unit 2 DER history for the last two years for similar problems associated with system restoration.

DER 2-94-1612: The inspectors reviewed the DER and surveillance test procedure N2-ISP-RHS-Q022, "Quarterly Functional Test of the RHS Pump Discharge Flow Instrument Channels," and concluded that the procedure in-place at the time of the event was weak, but no violation occurred. The corrective actions taken as a result of the event were adequate.

DER 2-95-0237: The inspectors reviewed the DER and maintenance procedure N2-MMP-GEN-200, "Valve Packing," and determined that NMPC failed to follow this procedure. Specifically, the procedure required that, following valve packing replacement, the valve be returned to the as-found position. Two contributing factors to this event were the lack of procedural requirement to document the as-found valve position, and the decision of the Station Shift Supervisor (SSS) not to perform a valve line-up based on the limited scope of the work performed. This event occurred while Unit 2 was shutdown and NMPC personnel identified and corrected the problem prior to the requirement for reactor core isolation cooling (RCIC) to be operable. The corrective actions taken as a result of the event were adequate. Nonetheless, the failure to follow the procedure is a violation of technical specification (TS) 6.8.1 regarding procedure compliance. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

DER 2-95-01854: This issue was also documented in Licensee Event Report (LER) 50-410/95-06, which was previously reviewed in NRC Inspection Report (IR) 50-410/95-23. Therefore, no additional review of this issue was preformed.

Subsequent to the above described events, NMPC improved their controls to ensure proper restoration following maintenance or testing activities. Specifically, maintenance and test procedures were reviewed and revised. The revisions included steps for returning each component manipulated within the procedure back to the proper position. A similar philosophy was incorporated into the development of work orders (WOs), such that individual steps are provided for the restoration of each component manipulated within the WO. Also, additional guidance regarding system restoration following tagout activities was provided in NMPC's administrative procedures and Operations Manual. Based on the inspectors' routine review of maintenance and test activities, the inspectors concluded that the controls were adequate.

The inspectors reviewed Unit 2 DERs for issues associated with configuration control problems following maintenance and testing activities that had occurred over the last two years. There were several DERs associated with configuration control that NMPC had identified. In general, the issues described in the DERs reviewed indicated human performance error and not problems with the controlling process. Also, these issues were generally minor in nature. An exception noted concerned DER 2-98-2937, which documented that a unit 2 standby liquid control system pump suction isolation valve was improperly left closed following a surveillance test. The issue was described in NRC inspection report 50-410/98-15. The inspectors had no further concerns regarding this issue. This unresolved item is closed.

M8.2 (Closed) VIO 50-220/97-07-02: Missed technical specification surveillance requirement on channel 11 control room vent radiation (CRVR) monitor. The Unit 1 technical specifications require that an instrument channel calibration be performed once each operating cycle, not to exceed 24 months, for the control room ventilation radiation monitor. Unit 1 personnel identified that the 11 CRVR monitor had not been calibrated within the time requirements. The cause was determined to be personnel error due to inattention-to-detail and inadequate self-checking during the preventive maintenance/surveillance test database update. Corrective actions included management reinforcement of accuracy in database update and additional training. The CRVR monitor was successfully calibrated. The inspector reviewed the NMPC response to the violation in a letter to the NRC dated December 29, 1997, and verified that the corrective actions had been taken. The inspector determined that corrective actions were acceptable. This violation is closed.

M8.3 (Closed) VIO 50-410/97-07-03: Missed technical specification surveillance requirement on hydrogen recombiner system (HCS) instrumentation. The Unit 2 technical specifications require HCS system instrumentation calibration at least once every 18 months. During an ongoing review, NMPC determined that the HCS instrumentation calibration had not been completed since the initial operation of Unit 2. The causes were determined to be that the original procedure was not adequately developed and the deficiency was not identified during subsequent procedure revisions. NMPC revised the surveillance procedure and completed the surveillance testing. The HCS instrumentation was determined to be within the required tolerances. The inspector reviewed the NMPC response to the violation in a letter to the NRC dated December 29, 1997 and verified that the corrective actions had been taken. The inspector determined that corrective actions were acceptable. This violation is closed.

M8.4 (Closed) LER 50-410/98-15: Missed surveillance requirements for division I and II emergency diesel generators (EDG). NMPC determined that previous surveillance testing, prior to 1989, did not adequately verify that all automatic EDG trips were automatically bypassed upon loss of voltage on the emergency bus concurrent with a emergency core cooling system (ECCS) actuation signal. The EDGs have protective systems designed to initiate an EDG shutdown to prevent damage to the EDG should a malfunction occur during the test mode. During the emergency mode of operation these automatic trips are bypassed. The inspectors completed an onsite review of the LER and discussed the logic circuitry, testing methodology, and current test practices with NMPC staff. The inspector considered the root cause and corrective actions to be reasonable. The description and analysis of the event, as contained in the LER, were consistent with the inspectors' understanding of the event. This licensee identified and corrected discrepancy constitutes a violation of minor significance and is not subject to formal enforcement action.

III. Engineering

E1 Conduct of Engineering

E1.1 Root Cause Determination and Corrective Actions associated with the Failed Reactor Recirculation Flow Control Valve (Unit 2)

a. Inspection Scope (37551, 62707)

The inspectors assessed the root cause determination and corrective actions for the "B" reactor recirculation system (RCS) flow control valve (FCV) failure. The assessment included a review of the associated deviation/event reports (DERs), visual inspection of the RCS FCV, and discussions with NMPC personnel.

b. Observations and Findings

On November 13, 1998, the "B" RCS FCV failed, and the "B" RCS loop was removed from service. On November 23, following repairs to the system, NMPC attempted to recovery the loop. However, during the recovery, the FCV exhibited irregular position indications. As a result, NMPC management directed the operators to shutdown the unit for further troubleshooting of the FCV.

The licensee's activities regarding the Unit 2 recirculation flow control valve failure that were completed prior to November 21 were documented in NRC inspection report 50-410/98-15. At that point in time, NMPC believed the FCV operating problems were repaired. However, they were unable to positively identify the initiating cause of the event.

During the shutdown, NMPC determined that the rotary variable differential transformer (RVDT) mechanical coupler was broken. The RVDT is mounted on the RCS FCV, located in the drywell, and provides a valve position feedback signal to the RCS FCV control circuit. NMPC replaced and recalibrated the RVDT. The broken RVDT and coupler were sent to an independent laboratory for material failure analysis. In addition, they inspected the RVDT on the "A" FCV with no problems noted.

Discussion with NMPC indicated that the broken RVDT coupler was the cause of the November 13 event. NMPC believed that during the troubleshooting of the November 13 event, the broken portions of the RVDT were retained by spring force allowing the results of the repairs outside the drywell to appear satisfactory. It wasn't until the RCS pump was started than enough impact was applied to the RVDT to overcome the spring force and separate the coupler, providing the licensee with indications that the FCV required additional investigation.

The RVDT couplers have failed previously at Unit 2, and the past failures of the RVDT and/or coupler were part of the basis for the RCS being a maintenance rule category a(1) system. NMPC has not yet determined the cause for these failures, but suspects high vibration to be a contributor to the failures. Furthermore, NMPC is still evaluating long term corrective actions for the problem.

The inspectors considered the licensee's cause determination to be technically sound in that the broken RVDT caused the failure of the RCS Loop "B" FCV. However, the root cause of this failure and previous RVDT and coupler failures is still unknown. The inspectors noted that the RCS FCV RVDT and coupler are not safety-related and therefore, not subject to the requirements of 10 CFR 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plant and Fuel Reprocessing Plants." However, the failure to identify and prevent recurrence of previous RVDT and/or coupler failures resulted in a challenge to the operators.

c. Conclusions

Activities associated with the reactor coolant system flow control valve failure cause determination and repair were acceptable and technically sound. However, previous actions to address the flow control valve degradation were not effective in preventing recurring problems.

E1.2 Difficulties in Controlling Unit 2 Reactor Vessel Water Level during Plant Startup due to Inadequate Modification

a. Inspection Scope (37551)

During the November 30, 1998, plant startup of Unit 2, operators experienced difficulties controlling reactor vessel water level. The inspectors discussed the event with the operators and reviewed operator's logs. In addition, the inspectors reviewed the applicable deviation/event reports (DERs) including the cause determination, and immediate and preventive actions taken. The Inspectors also discussed related issues with the applicable system engineer and the Unit 2 Engineering Manager.

b. Observations and Findings

During the Unit 2 plant startup, while the feedwater pumps were still secured, the operators experienced an unexpected rise in reactor vessel water level when they opened the feedwater header blocking valves. In response, operators maximized reactor water cleanup reject flow, reduced control rod drive flow, and closed the startup level control valves, but level continued to rise. Not until the operators isolated the condensate system from the feedwater system did the level rise stop. In all, level rose from 185 inches to 191 inches within a half-hour. Normally, reactor vessel water level is maintained between 178 and 187 inches. Subsequent investigation by NMPC identified that the source of injection water was from the condensate booster pumps through the depleted zinc oxide (DZO) skid into the feedwater system downstream of the feedwater blocking valves. The DZO skid was isolated, reactor vessel water level control was restored and the plant startup was completed. NMPC documented the event in a DER for evaluation.

The DZO system injects zinc into the reactor feedwater to control radiation within the reactor coolant system. NMPC installed the DZO skid during the last refueling outage in June 1998, to replace the zinc injection passivation (ZIP) skid. The DZO system is a passive system that uses the differential pressure across the feedwater pumps to provide the motive force for zinc injection. Specifically, the DZO skid takes a suction from the discharge of the feedwater pumps, then returns the zinc-enriched water to the suction of

the feedwater pumps for injection to the reactor coolant system through the normal feedwater path.

NMPC determined that the DZO skid did not contain a reverse flow check valve like that which was included in the previously installed ZIP skid. Since, at the time of the event the feedwater pumps were still secured, the discharge of the condensate booster pump flowed through the DZO skid, bypassing the normal blocking and level control valves allowing water to inject into the vessel. As described in DER 2-98-3621, NMPC determined the apparent cause of the event to be a failure to anticipate the system interactions during the installation of the DZO skid. Their corrective actions included a procedure change to control the DZO skid lineup. Nonetheless, the failure to review the system interactions during the installation of Modification N2-89-076 associated with the DZO skid is a violation of 10CFR50 Appendix B, Criterion III, "Design Control." 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 5-410/98-19-02)**

The inspectors reviewed the DER and discussed the event with the system engineer. The inspectors concluded that although the DER was technically sound, and the corrective action to revise the procedure was appropriate, the DER failed to address the potential programmatic issues regarding the modification process. Subsequent to the end of the inspection period, the inspectors discussed this concern with the Unit 2 Engineering Manager and ascertained that the programmatic issues were being reviewed by NMPC, however, this review was not documented in the DER. Additionally, NMPC generated a new DER to evaluate this aspect of the issue. The inspectors reviewed this DER and considered it to be appropriate.

c. <u>Conclusions</u>

An inadequate review associated with the Unit 2 depleted zinc oxide injection modification, installed in June 1998, resulted in an unexpected rise in reactor vessel water level during November 30, 1998, plant startup. This licensee identified and corrective violation of design control was treated as a non-cited violation. **(NCV 50-410/98-19-02)** NMPC's review of the unexpected rise in reactor vessel water level was technically sound and they appropriately revised the operating procedures to prevent recurrence. However, a weakness was noted with the documentation of corrective action in NMPC's deviation/event report in that the evaluation did not include NMPC's ongoing evaluation of the modification process.

E8 Miscellaneous Engineering Issues (92700, 92712, 92903)

E8.1 <u>(Closed) URI 50-410/97-11-01:</u> Leakage of contaminated water in reactor building following scram reset. When a reactor scram is reset, contaminated water from the scram discharge volume spills out of the vent line onto the reactor building floor during automatic drain down of the scram discharge volume. The spillage from the vent line has occurred consistently when a reactor scram was reset. NMPC has compensated for this plant design anomoly by making a plant announcement to stand clear of the area during venting. NMPC has documented the additional occurrence on a DER following the November 24, 1998, manual scram to shutdown the plant. The inspectors reviewed the UFSAR and

regulatory requirements and, based on the current information, concluded this item would be more appropriately classified as an inspector followup item pending additional review of the system design. **(IFI 50-410/98-19-03)**

E8.2 <u>(Closed) URI 50-220/97-11-02</u>: Adequacy of the main steam isolation valve (MSIV) closure set point on high steam flow. The inspectors questioned whether a main steam line (MSL) break near the turbine would initiate a closure signal for the MSIVs. The concern was raised because the Final Safety Analysis Report (FSAR) stated that a steam line break, close to the turbine, would develop a differential pressure increase of 20 pounds per square inch (psi). The inspector combined this value with the normal full power operation value differential pressure of 70 psi, and determined that it was below the instrumentation trip setpoint of 102 pounds per square inch differential (psid). NMPC reviewed the question and initiated a DER when it was determined that the instrument trip set points lacked design calculations. NMPC subsequently determined that the wording in the FSAR was unclear and incorrect. The 20 psi venturi pressure loss was a characteristic of the venturi design, and was not intended to infer that a break near the turbine, would cause a differential pressure of 20 psi at the flow restrictor. The actual differential pressure developed across the venturi due to a steam line break near the turbine was determined to be about 185 psid, which is well above the trip setpoint. NMPC's safety evaluation concluded that the main steam venturi flow calculation, S11-01F004, validated TS, TS basis and UFSAR stated parameters associated with the MSL flow venturis under normal as well as MSL break accident scenarios. The safety evaluation also proposed to correct the venturi pressure loss statement in the UFSAR and to clarify the critical flow statements. The inspector reviewed the calculations, safety evaluation, and DER responses and found them to be of good depth and scope. The inspector determine that there was no violation of NRC requirements as the set point was validated by NMPC and actions were taken to clarify the FSAR. This unresolved item is closed.

E8.3 <u>(Closed) URI 50-220/97-11-06</u>: Reactor water level system inoperability caused by leakage through drain valves. While performing maintenance on the reactor water level system, operators mistakenly attributed erratic level indication to ongoing maintenance activities. When the maintenance was completed the anomaly stopped and the system was declared operable. Subsequent review by NMPC engineering determined that the system was not operable because of potential system leakage masked by the backfill system. Licensee event report, LER 50-220/97-09, Technical Specification Violation Due to System Inoperability Caused by Leakage Through Drain Valves, discusses the issues surrounding the event and was reviewed in NRC inspection report 50-220/97-11. The LER was found to be timely and accurate. NMPC's immediate corrective actions were considered appropriate. The NRC previously determined NMPC long-term corrective actions to be sufficient to prevent recurrence. The inspectors determined that no violation of TSs occurred. This period the inspectors reviewed the NMPC's root cause analysis and subsequent corrective actions. NMPC determined that the effects of changing operating parameters were not properly evaluated by the operators. In addition, the post maintenance/modification testing activities did not consider possible level indication variations and the possibility of leaks going unnoticed because the normal operation of the backfill system provides a constant supply of make-up water. Corrective actions included procedure revisions to identify the potential for system isolation valve leakage, testing

during plant startup, and periodically testing the system for leakage. The inspectors concluded that the corrective actions were good. This unresolved item is closed.

E8.4 (Closed) VIO 50-410/97-11-03: Technical specification violation of average power range monitor testing requirements. During a design review for a neutron monitoring system modification, NMPC identified that the technical specification surveillances for the average power range monitors "E" and "F" were not performed due to procedure inadequacies. The surveillance test was subsequently performed satisfactorily. NMPC reported the oversight in LER 50-410/97-11, Technical Specification Violation of APRM Testing Requirements, which was reviewed and closed in NRC inspection report 50-410/97-11. The inspector documented that the root cause and corrective actions documented in the LER were reasonable. NMPC responded to the violation in a letter to the NRC dated January 27, 1998. The inspector verified that the corrective actions documented in the letter were completed. This violation is closed.

E8.5 (Closed) VIO 50-410/97-11-04: Missed technical specification surveillance requirement of control room envelope. NMPC identified that the technical specification surveillance requirements for the control room outside air special filter train system was not being met. The procedure did not include testing of the control building relay room. The positive pressure verification of the control room envelope had failed to include the relay room since initial operation. Subsequently the surveillance test was completed satisfactorily. The issue was reported to the NRC in LER 50-410/97-09, Missed Technical Specification Surveillance of the Control Room Envelope, which was reviewed and closed in NRC inspection report 50-410/97-11. The inspector documented that the root cause and corrective actions in the LER were reasonable. NMPC responded to the violation in a letter to the NRC dated January 27, 1998. The inspector verified that the corrective actions documented in the letter were completed. This violation is closed.

E8.6 (Closed) LERs 50-410/98-14 and 50-410/98-14-01: Systems Outside the Design Basis Due to Incorrect Valve Weights

a. Inspection Scope (90712, 92700)

On May 25, 1998, while Unit 2 was shutdown for refueling outage six (RFO6), Niagara Mohawk Power Corporation (NMPC) personnel determined that differences between actual valve weights and weights shown on engineering drawings could have caused pipe stresses to exceed design allowables on four piping systems. The inspectors completed an on-site review of the issues associated with these Licensee Event Reports (LERs). Particularly, the inspectors assessed the licensee's root cause analysis and corrective actions as described in the LERs, which included a review of the technical specifications (TSs), Update Final Safety Analysis Report (UFSAR), the associated Deviation/Event Report (DER), engineering supporting analysis (ESAs), and plant drawings. The inspectors also discussed the issue with members of the Unit 2 Design Engineering Department including the Unit 2 Design Engineering Manager. In addition, the inspectors verified the completion of the LER in accordance with 10CFR50.73.

b. Observations and Findings

In May 1997, Unit 2 personnel identified that the weight of certain safety-related valves was greater than the weight shown on the vendor valve drawings. The differences were noted to be as great as 50 percent. The discrepancy was associated with 522 small bore American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) Class 2 and 3 manual valves. The use of incorrect valve weight impacts pipe stresses, pipe support/tie-back support loads and qualification of valve accelerations. Since the valves were all manual valves, and the pipes and pipe supports/tie-back supports are passive components, the safety functions for these components consisted of maintaining structural integrity and thus the pressure boundary. Upon identification of the discrepancy, NMPC issued a DER. NMPC completed an ESA that provided a preliminary bases for the operability of the effected systems. The ESA used a sampling of 400 valves for a variety of locations, loading conditions and configurations, and the conservatism included in the calculations and concluded that the affected valves, piping and systems met design requirements. At the time of the event, the inspectors reviewed the ESA and determined it to be reasonable. In addition, the inspectors considered the identification of this discrepancy to be an example of a good questioning attitude by NMPC.

On May 25, 1998, during the revision of the affected calculations to include the correct valve weights, NMPC determined that eight valves on four different systems caused the piping on those systems to not meet design requirements under normal operating and accident conditions. However, NMPC determined that the affected systems were either operable for the current shutdown conditions or were already out-of-service for other outage-related activities.

After additional evaluation, NMPC determined that three of the eight valves identified on May 25, 1998, met design requirements under all conditions. After this additional evaluation, the following three systems were still affected:

- residual heat removal system (RHS) Loop "C";
- reactor core isolation cooling (RCIC) system; and
- reactor building floor drain (DFR) system.

During their evaluations of the five valves that were not meeting the design requirements, NMPC identified additional errors associated with three valves. These errors involved incorrect valve weights in the original analysis (other than the vendor-provided weight discrepancy) and piping configuration errors that did not match the plant configurations. Subsequently, NMPC determined that these errors alone caused these three valves not to meet the pipe stress design allowables.

The inspectors reviewed the impacted on each system individually.

RHS

The RHS System removes decay and sensible heat during and after plant shutdown, injects water into the Reactor Pressure Vessel (RPV) following a Loss of Coolant Accident (LOCA) to reflood the core independently of other core cooling systems, and remove heat

from the primary containment following a LOCA, to limit the increase in primary containment pressure and temperature.

RHS was affected by two normally closed vent valves on a three-quarter inch line on the RHS Loop "C" injection line. These valves are used as high point vents and also as a vent during Type C testing of the Containment Isolation Valves (CIVs). A failure of theses valves could result in a three-quarter inch hole on the RHS Loop "C" injection line. NMPC evaluated this failure with respect to a postulated LOCA and concluded that although the RHS Loop C injection capacity would have been slightly reduced, the resulting injection flow rates would still be higher than those used in the LOCA analysis. Therefore, the small reduction in injection flow would not have significantly affected the heat removal and core cooling function of the RHS.

RCIC

The RCIC system provides adequate core cooling in the event the reactor is isolated from its primary heat sink and feedwater flow is not available. However, the RCIC system is not credited in accident analysis.

The RCIC system was affected by a normally closed one-half inch test connection on the RCIC turbine exhaust line to the suppression pool. A failure of this valve during RCIC operation would result in the release of steam from the turbine exhaust line that could lead to a RCIC isolation on area high temperature. A RCIC isolation condition is alarmed in the control room and would prompt the operators to take appropriate actions in accordance with procedures to place the plant in a safe condition. Additionally, the high pressure core spray (CSH) system serves as a backup to RCIC, can perform the same function as RCIC and would not have been affected by the failure in the RCIC system. Nonetheless, the RCIC system was considered inoperable from initial plant startup until the discrepancy was corrected during RFO6. Piping configuration changes were made such that design requirements were reestablished.

DFR

The reactor building floor drains collect leakage from radioactive or potentially radioactive sources and high conductivity or potentially high conductivity sources and discharge these fluids to the Radwaste System for processing.

The reactor floor drain system was affected by two normally closed three-quarter inch test connection on the drains leaving containment. This pipe connection is located in the air space above the suppression pool. The failure of these valves would result in a bypass path between the suppression pool and drywell atmospheres. The bypass area between the suppression pool and the drywell is limited to maintain the energy removal capability of the suppression pool during a LOCA. This bypass path would have resulted in an additional bypass area of approximately six percent of design. However, this additional bypass area plus actual bypass area determined by previous performance testing was within the TS Limiting Condition for Operations (LCO) 3.6.2.1.b limit of 10 percent. Therefore, the plant was within the TS limit and the containment barrier would have been assured.

In addition to the impact on the systems described above, NMPC evaluated the impact of the failures with respect to changes in radiological consequences, and they determined them to have been minimal. The inspectors considered NMPC's review of the issue to be comprehensive and thorough.

Technical Specification 3/4.4.8, "Structural Integrity," requires that the reactor coolant system structural integrity of ASME Code Class 1, 2, and 3 components be maintained. When the integrity of these components fails to meet the applicable requirements, the affected components must be returned to within limits or must be isolated. This TS applies to the piping associated with the two RHS valves since this piping is part of the reactor coolant pressure boundary. Therefore, due to the discrepancy, the RHS piping did not meet the applicable requirements since original installation. Furthermore, since this discrepancy was not recognized and repaired until May 1998, the applicable TS actions were not taken. In addition, the failure to have RCIC operable from initial startup until May 1998 was a violation of TS 3.7.4. These non-repetitive, licensee-identified and corrected issues are being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-410/98-19-04)**

The inspectors reviewed LER 50-410/98-14 upon issuance, and noted that although the associated DER provided details regarding the licensee's design control errors, this information was not contained within the LER. Following a discussion with the Unit 2 Engineering Branch Manager, NMPC supplemented the LER to include this information.

The inspectors verified that the LERs were completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LERs, were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LERs were reasonable. These LERs are closed.

c. <u>Conclusions</u>

Niagara Mohawk Power Corporation demonstrated a good questioning attitude when they identified that the weight of 522 safety-related valves at Unit 2 was greater than the weight shown on the vendor valve drawings. Following a comprehensive and thorough evaluation, the licensee determined that a total of five valves within residual heat removal, reactor core isolation cooling and reactor building floor drain systems caused the associated piping not to meet design requirements under all conditions. **(NCV 50-220/98-19-04)**

E8.7 <u>(Closed) LER 50-410/98-20: Previous Inoperability of Reactor Core Isolation Cooling System Valves</u>

a. <u>Inspection Scope (90712, 92700)</u>

On June 23, 1998, while Unit 2 was shutdown for refueling outage six, NMPC personnel determined that the RCIC system had been inoperable from initial startup until December 1993. The inspectors completed an on-site review of the issues associated with this LER. Particularly, the inspectors assessed the licensee's root cause analysis and corrective actions as described in the LER, including a review of the TS, UFSAR, and associated

DER and plant drawings. The inspectors also discussed the issue with members of the Unit 2 Technical Support and Design Engineering Departments. In addition, the inspectors verified the completion of the LER in accordance with 10CFR50.73.

b. Observations and Findings

During NMPC's Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits," review, they identified a design deficiency associated with three motor-operated valves in the RCIC system. Specifically, NMPC identified that the seal-in contacts within the control circuits of these valves were in series with overload relays contacts. Should the overload relays trip in conjunction with a transitory RCIC initiation signal, the seal-in function would have been lost. This design deficiency was not in accordance with UFSAR Section 7.4.2.1.3.1, which states "Once the RCIC is initiated by reactor low water level, the logic seals in and the system operation must go to completion until terminated by deliberate Operator action or automatically stopped on high vessel water level or system malfunction trip signal."

This deficiency existed from initial plant startup until December 1993, when shorting bars were installed that inactivated the overload heaters. The shorting bars were installed to eliminate voltage drop across the overload heaters so as to improve valve performance to meet GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance" This modification unknowingly corrected the deficiency associated with the seal-in contacts. However, the deficiency was not identified during the design and safety analysis associated with the modification.

The function of the RCIC system is to provided adequate core cooling in the event of reactor isolation form the primary heat sink and loss of feedwater flow to the reactor vessel without requiring actuation of any emergency core cooling system equipment. Should the RCIC system have failed, the ECCS system was capable of providing adequate core cooling.

The inspectors considered the identification of this design deficiency as an example of good questioning attitude by NMPC, in that deficiency was identified during the licensee's GL 96-01 review even though the deficiency was not related to the issues in GL 96-01. Nonetheless, the failure to have RCIC operable from initial plant startup until December 1993 was a violation of Technical Specification 3.7.4. 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 50-410/98-19-05)**

The inspectors verified that the LER was completed in accordance with the requirements of 10CFR50.73. 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. <u>Conclusion</u>

Niagara Mohawk Power Corporation demonstrated a good questioning attitude during their Generic Letter 96-01 review by identifying an unrelated discrepancy associated with three motor-operated valves within the Unit 2 reactor core isolation cooling system. Specifically, the seal-in contacts within the control circuits of these valves were in series with overload relay contacts. Should the overload relays trip in conjunction with a transitory RCIC initiation signal, the seal-in function would have been lost, rendering the system incapable of performing the design function. This discrepancy existed from initial plant startup until it was unknowingly corrected by an unrelated modification in December 1993. **(NCV 50-410/98-19-05)**

E8.8 <u>(Closed) URI 50-410/97-04-10</u>: Basis for no LER for a condition outside design basis. On April 11, 1997, Unit 2 made a 10CFR50.72 report regarding a discrepancy identified in the control circuitry of a Division I EDG SW valve that placed the plant in a condition outside the design basis. This item was opened because NMPC did not issued an LER addressing this concern nor were the inspectors able to obtain a documented basis justifying why the condition was not reportable under 10CFR50.73.

As a result of this concern, NMPC revised the DER associated with the event to provided the basis for not reporting it. In addition, on July 27, 1997, NMPC retracted the 10CFR50.72 notification in accordance with the guidance provided in NUREG 1022. The inspectors completed an onsite review of this issue. In particular, the inspectors reviewed the basis for not reporting the event as contained in the revised DER and determined it to be technically sound, therefore, no violation of 10CFR50.73 had occurred. However, NMPC Procedure NIP-ECA-01, "Deviation/Event Report," Revision 11, required that during the disposition of events previously considered reportable, if it is determined that the event was not reportable, adequate supporting justification is to be provided in the DER disposition. The failure to provide this justification in DER 2-97-1136 was a violation of licensee procedure and is considered a violation of TS 6.8.1. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. This item is closed.

E8.9 <u>(Closed) URI 50-410/96-15-01:</u> Potential for loss of remote shutdown capability due to multiple hot shorts. The inspectors reviewed the UFSAR and regulatory requirements and, based on the current information, concluded this item would be more appropriately classified as an inspector followup item pending additional review. **(IFI 50-410/98-19-06)**

<u>IV. Plant Support</u>

P2 Status of EP Facilities, Equipment, Instrumentation and Supplies

a. <u>Inspection Scope (82701)</u>

The inspector conducted an audit of emergency equipment in the control room, the operations support center (OSC), the technical support center (TSC), the emergency operations facility (EOF) and the Joint News Center (JNC). The inspector reviewed 1998

emergency equipment surveillance and communications test records for completeness and accuracy.

b. Observations and Findings

An audit of equipment and supplies in the control room, the OSC, the TSC, the EOF and the JNC indicated that specified equipment was present. The facilities were well equipped, orderly, and ready for immediate activation. The emergency preparedness (EP) staff conducts monthly walk-throughs of the facilities to monitor overall status and to ensure readiness. Current revisions of the emergency plan and implementing procedures were present in the facilities. Selected radiological monitoring instrumentation was checked and operability was verified. NMPC has planned to move the OSC to an area adjacent to the TSC to enhance communications and to bring OSC personnel within the same protective ventilation envelope as the control room and TSC. A review of completed surveillances for the facilities and communications tests for 1998 indicated that they were performed as required. Discrepancies identified during the surveillances and communication tests were promptly resolved. Siren and emergency response organization (ERO) pagers tests were also conducted as required.

c. Conclusions

Emergency preparedness equipment surveillances and communication tests were performed as required and the facilities and equipment were determined to be in a good state of operational readiness.

P3 EP Procedures and Documentation

a. Inspection Scope (82701)

The inspector assessed the process used by the licensee to review and change the emergency plan (Plan) and implementing procedures (IPs), reviewed recent changes to assess the impact on the effectiveness of the Plan, and ensured that periodic reviews were completed as required.

b. Observations and Findings

Prior to this inspection, the inspector conducted an in-office review of recent Plan and IP changes. Based upon the licensee's determination that the changes did not decrease the overall effectiveness of the Plan and after review of the changes, no NRC approval was required in accordance with 10 CFR 50.54(q). During this inspection, it was determined that the licensee's 10 CFR 50.54(q) review (effectiveness review) process was well controlled. The inspector reviewed the assessments of several Plan and IP changes and determined that the changes were acceptable. Regular Plan and IP reviews were performed by the licensee. Letters of agreement with offsite organizations were determined to be current.

c. Conclusions

A review of NMPC's emergency preparedness procedure change review process, and a sampling of recent changes, indicated that a good change control program was being implemented.

P5 Staff Training and Qualification in EP

a. Inspection Scope (82701)

The inspector reviewed training records and requirements to evaluate the implementation of the ERO training program.

b. Observations and Findings

Requalification training records for several ERO members were checked to verify that they had received annual training. Likewise, records for newly qualified ERO members indicated they had received the required training. NMPC successfully monitors and maintains a four team rotation for key ERO positions. Selected training modules were reviewed to ensure that the required EP director's (EPD) review and approval had been performed. Required drills had been conducted. Drill reports were appropriately self-critical and issues were identified at a low threshold. The inspector verified comments from procedure changes and drill reports were incorporated into subsequent training. Offsite drills and training, including the annual emergency action level training for state and local officials, were conducted in accordance with the Plan.

c. Conclusion

The emergency response organization (ERO) training program was well implemented in that ERO members' qualifications were current and drills were conducted as required.

P6 EP Organization and Administration

The EP department has remained at a constant staffing level although there has been a change in personnel within the department since the last EP program inspection and the EPD reports to a new manager. No adverse impact on the EP program was observed as a result of these changes. The EP department adheres to procedural guidance, such as EP maintenance procedures (EPMP), to implement the program. NMPC has successfully scheduled and tracked EP-related activities, such as, facility surveillances, communication tests, and drills, to ensure that the program was being properly implemented. The EP program continued to receive strong management support as evidenced by cooperation from supporting departments and by management participation in the ERO.

P7 Quality Assurance (QA) in EP Activities

a. Inspection Scope (82701)

The inspector reviewed NMPC's processes for identifying and tracking EP-related issues and assessed the effectiveness of problem resolution. The inspector interviewed the lead auditor for the 1998 audit, reviewed the 1997 and 1998 QA audit reports and the 1998 audit checklist to assess the effectiveness of the EP program audits. Additionally, EP drill performance records were reviewed.

b. Observations and Findings

NMPC uses several methods for problem identification which include audits, self-assessments, and drill or exercise evaluations. The issues in the EP department's deficiency tracking system were reviewed and it was determined that an appropriate threshold for problem identification existed. The most significant issues were appropriately tracked through Deviation/Event Reports (DERs). Corrective actions were appropriate as significant recurrences were not noted.

The EP audit and surveillance teams for the 1997 and 1998 audits consisted of several persons, at least one of whom possessed technical expertise. The checklist used for the 1998 surveillances was determined to be sufficiently detailed to assess the program. The 1997 and 1998 audit reports identified specific issues within the EP program and the documentation supported the conclusions. No issue was indicative of a programmatic weakness. The subjects specified by 10 CFR 50.54(t) were addressed and the reports contained recommendations for program enhancement. There were no repeat issues from 1997 to 1998 as corrective actions were appropriate. The reports were distributed to the appropriate levels of licensee management and the portions of the reports addressing the offsite interface were made available to offsite officials. EP drill performance records showed generally good performance.

c. Conclusions

Based upon generally good performance during drills, the absence of repeat audit or self-assessment findings, and no significant adverse trends in the emergency preparedness (EP) program, the problem identification and corrective action processes were determined to be effective. The EP program audits were thorough and the reports were useful for NMPC management to assess the effectiveness of the EP program.

P8 Miscellaneous Emergency Preparedness Issues (92904)

P8.1 (Closed) VIO 50-220 and 50-410/97-06-04: Annual retraining of some ERO members was not completed. Nine members of the dose assessment staff at the EOF had lapsed in their qualifications; however, they continued to be listed on the ERO roster. The failure to maintain the training requirements of the approved Plan was a violation of NRC requirements. During this inspection, it was verified that the licensee had performed the corrective and preventive actions stated in the licensee's DER No. C-97-2081 which was written to address this violation. Examples of these actions included conducting

requalification training for the nine individuals with expired qualifications, reviewing training records for other ERO members to ensure current qualifications, and reminding all ERO members of their responsibility to maintain their qualifications. The inspector reviewed the current ERO members' training records and verified that no individuals with expired qualifications were on the roster. This violation is closed.

P8.2 (Closed) VIO 50-220 and 50-410/97-06-05: An annual ERO augmentation callout drill was not performed since 1994. Procedure EPMP-EPP-01, Maintenance of Emergency Preparedness, required the conduct of an annual ERO augmentation drill, by activation of the notification system, with actual personnel response from offsite to the emergency facilities. The inspectors determined, through discussion with the EPD, that a call-out of the ERO with actual report to the facilities from offsite had not been performed since November 1994. The licensee had failed to recognize the existence of this requirement, despite its explicit wording, and was taking credit for its completion with the performance of the periodic call-out drills in which ERO members respond via telephone with an estimate of their reporting time. The failure to conduct the annual callout drill was a violation of the Plan and the EPMP.

During this inspection, it was determined that the licensee never intended to conduct annual augmentation drills and that the wording of EPMP-EPP-01 was incorrect. It was determined that the licensee had revised EPMP-EPP-01 to accurately reflect the requirement of augmentation drills every six years instead of annually. This violation is closed.

P8.3 (Closed) IFI 50-220 and 50-410/97-010-01: Licensee staffing during the exercise exceeded that which is specified in the Plan. During the September 1997 exercise, the inspectors observed that several ERO positions were double-staffed. This item was opened because the inspectors could not assess the adequacy of the Plan's designated staffing and were concerned that with multiple staff in various positions, the licensee would be challenged to staff those positions on a 24 hour basis.

During this inspection, it was determined that the licensee double-staffed certain positions to accommodate the needs of the offsite agencies participating in the exercise and to ensure that the necessary response duties of those positions would be performed. When offsite agencies are not participating in exercises, the licensee drills with minimum staffing. Overall, licensee drill performances utilizing minimum staffing have been satisfactory, therefore, the adequacy of the Plan has been demonstrated. To assess the licensee's capability to staff the ERO on a 24 hour basis, the inspector verified that sufficient numbers of qualified ERO members are available to double-staff the positions which were double-staffed during the 1997 exercise to fill two 12 hour shifts. Furthermore, during an emergency, it is the responsibility of the administrative logistics manager to ensure that 24-hour staffing can be accomplished. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on January 25, 1999. The licensee acknowledged the findings presented.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

INSPECTION PROCEDURES USED

IP 37551	On-Site Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support
IP 82701	Operational Status of the Emergency Preparedness Program
IP 90712	In-Office Review of Written Reports of Non-Routine Events at Power Reactor Facilities
IP 92700	Onsite Follow-up of Written Reports of Non-Routine Events at Power Reactor Facilities
IP 92901	Follow-up - Operations
IP 92902	Follow-up - Maintenance
IP 92903	Follow-up - Engineering
IP 92904	Follow-up - Plant Support
IP 93702	Event Response

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/98-19-01	NCV	Failure to complete TS surveillance tests for SRMs and IRMs during shutdown
50-410/98-19-02	NCV	Difficulties in controlling Unit 2 reactor vessel water level during plant startup due to inadequate modification.
50-410/98-19-03	IFI	Leakage of contaminated water in the reactor building following scram reset.
50-410/98-19-04	NCV	Systems did not meet design requirements due to pipe stresses
50-410/98-19-05	NCV	RCIC logic design deficiency
50-410/98-19-06	IFI	potential for loss of remote shutdown capability due to multiple hot shorts

CLOSED

50-410/98-19-01	NCV	Failure to complete TS surveillance tests for SRMs and IRMs during shutdown

50-410/98-19-02	NCV	Difficulties in controlling Unit 2 reactor vessel water level during plant startup due to inadequate modification.
50-410/98-19-04	NCV	Systems did not meet design requirements due to pipe stresses
50-410/98-19-05	NCV	RCIC logic design deficiency
50-220/97-07-02	VIO	Missed technical specification surveillance requirement on channel 11 control room vent radiation monitor.
50-410/97-07-03	VIO	Missed technical specification surveillance requirement on hydrogen recombiner system instrumentation.
50-410/98-15	LER	Missed surveillance requirements for division I and II emergency diesel generators.
50-220 & 50-410/97-80-01	VIO	DERs extended without justification.
50-410/98-27	LER	Missed technical specification required surveillance of SRMs and IRMs prior to mode change.
50-410/98-28	LER	Inadvertent isolation of RCIC and SDC due to a spurious trip of temperature switch.
50-410/96-07-06	URI	Inadequate restoration after maintenance/testing.
50-410/97-11-01	URI	Leakage of contaminated water in reactor building following scram reset.
50-220/97-11-02	URI	Adequacy of the main steam isolation valve closure set point on high steam flow.
50-220/97-11-06	URI	Reactor water level system inoperability caused by leakage through drain valves.
50-410/97-11-03	VIO	Technical specification average power range monitor testing requirements.
50-410/97-11-04	VIO	Missed technical specification surveillance requirement of control room envelope.
50-410/98-14 & 50-410/98-14/01	LER	Systems outside the design basis due to incorrect valve weights.
50-410/98-20	LER	Previous inoperability of reactor core isolation cooling system valves.
50-410/97-04-10	URI	Basis of no LER for a condition outside design basis.

50-41-/96-15-01	URI	Potential for loss of remote shutdown capability due to multiple hot shorts.
50-220 & 50-410/97-06-04	VIO	Annual retraining of some ERO members was not completed
50-220 & 50-410/97-06-05	VIO	An annual ERO augmentation callout drill was not performed since 1994
50-220 & 50-410/97-10-01	IFI	Licensee staffing during the exercise exceeded that which is specified in the Plan.

LIST OF ACRONYMS USED

ASME	American Society of Medical Engineers
ASSS	Assistant Station Shift Supervisor
CFT	Channel Functional Test
CIV	Containment Isolation Valve
CRVR	Control Room Vent Radiation
CSH	High Pressure Core Spray
DER	Deviation/Event Report
DFR	Reactor Building Floor Drain
DZO	Depleted Zinc Oxide
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generators
EOF	Emergency Operating Facility
EP	Emergency Preparedness
EPD	Emergency Preparedness Director
EPMP	Emergency Preparedness Maintenance Procedure
ERO	Emergency Response Organization
ESA	Engineering Supporting Analysis
ESF	Engineered Safeguards Feature
FCV	Flow Control Valve
GL	Generic Letter
HCS	Hydrogen Recombiner System
HCU	Hydraulic Control Unit
IFI	Inspector Followup Item
IRM	Intermediate Range Monitors
JNC	Joint News Center
LCO	Limiting Conditions for Operation
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Coolant Spray
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MSIV	Main Steam Isolation Valve

MSL	Main Steam Line
MSR	Moisture Separator Reheater
NCV	Non-Cited Violation
NMPC	Nine Mile Point Corporation
NRC	Nuclear Regulatory Commission
OSC	Operations Support Center
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RCS	Recirculation System
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
RVDT	Rotary Variable Differential Transformer
SDC	Shutdown Cooling
SORC	Station Operating Review Committee
SRM	Source Range Monitors
SSS	Station Shift Supervisor
SW	Service Water
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Unit 1	Nine Mile Point Unit 1
Unit 2	Nine Mile Point Unit 2
VAR	Volt-Amperes Reactive
VIO	Violation
ZIP	Zinc Injection Passivation