U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Reactor Projects Section No. 1A
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Nine Mile Point Units 1 and 2
50-220/94-03 & 50-410/94-03

PLANT OPERATIONS

Both units operated essentially at full power throughout the period. A single control rod scram occurred on Unit 2 during reactor protection system scram testing. Louis F. Storz started as the Vice President-Nuclear Generation on March 1, 1994, and John Aldrich was named as the Unit 1 Maintenance Manager. Layoffs continue, with 106 professional and supervisory positions being abolished. An unresolved item was identified for possible leakage past pressure isolation valves between the reactor coolant system and the residual heat removal system on Unit 2 (URI 50-410/94-03-01). A second unresolved item in the operations area regards a safety evaluation that did not adequately justify a change in operating practices related to the Unit 1 nuclear instrumentation (URI 50-220/94-03-02).

MAINTENANCE

The inspectors monitored maintenance and surveillance activities and determined that they were conducted satisfactorily. Specific activities observed included repair of a Unit 1 test connection that caused a difference in reactor water level indications; on-line repair of the Unit 1 main transformer; and nitrogen system check valve testing on Unit 2. The Unit 2 safety-related maintenance backlog was reviewed and the inspectors concluded that NMPC is actively managing the backlog. The inspectors reviewed troubleshooting activities at both units and concluded that work is conducted in accordance with written instructions. A single control rod scrammed during weekly reactor protection system testing; during recovery, NMPC discovered wiring errors within RPS. Although the wiring was corrected after the inspection period ended; an unresolved item remains pending completion of the root cause evaluation (URI 50-410/94-03-03).

ENGINEERING

Operators discovered over 1000 gallons of ground water in the Unit 1 cable spreading room, leaking through electrical penetrations. An unresolved item remains pending resolution to several questions related to this event (URI 50-220/94-03-04).

SAFETY ASSESSMENT AND QUALITY VERIFICATION

NMPC identified that Unit 1 had previously violated Technical Specification surveillance requirements associated with the calibration of the source range (SRM) and intermediate range (IRM) nuclear instrumentation. Representatives from both units conducted a thorough review and concluded the IRMs were capable of performing their safety function of initiating a reactor scram. It is noted that the surveillance testing performed by NMPC during the period of August 1992 through April 1993 appears to be consistent with specific allowances

of similar plants. However, this does not alleviate NMPC from their responsibility to meet existing channel calibration surveillance requirements. This item was licensee identified and corrective actions were taken prior to the end of this report period. The safety significance of the missed surveillance tests was low based on the surveillance tests performed; there was reasonable assurance that the SRMs and IRMs were operable and would have performed their design functions.

Also during this report period, the inspectors noted examples, at both units, of poor procedure implementation. Each case was of minor safety significance by itself; but combined, there was a trend of inattention to detail.

DETAILS

1.0 SUMMARY OF ACTIVITIES

1.1 NMPC Activities

Unit Operations

The Niagara Mohawk Power Corporation (NMPC) safely operated Nine Mile Point Unit 1 (Unit 1) and Nine Mile Point Unit 2 (Unit 2) at essentially full power throughout the period. There were no transients or safety challenges for Unit 1. For Unit 2, a single control rod scrammed into the core during the weekly reactor protection system manual scram channel functional testing on February 22, 1994.

Management Changes

During this inspection period, two changes within the Niagara Mohawk nuclear organization were announced:

- Louis F. Storz was named as the Vice President - Nuclear Generation, effective March 1, 1994. Mr. Storz is responsible for the overall operations of both units at the Nine Mile Point site, with the Plant Managers reporting directly to him. The position of Vice President - Nuclear Generation has been vacant since June 1993, when Neil S. "Buzz" Carns left NMPC to accept a position at another facility.

- John C. Aldrich was named as the Unit 1 Maintenance Manager, effective March 1, 1994. Mr. Aldrich replaces Robert Tessier, who became Manager - Nuclear Training earlier this year. Mr. Aldrich is a licensed senior reactor operator (SRO), and is qualified as a Station Shift Supervisor.

1.2 NRC Activities

Resident inspectors conducted inspection activities during normal, backshift and weekend hours over this period. There were 31 hours of backshift (evening shift) and 11 hours of deep backshift (weekend, holiday, and midnight shift) inspection during this period. In addition, specialist inspections were conducted in the areas of radiation protection, fire protection, and engineering design. The results of these inspections will be reported separately.

2.0 PLANT OPERATIONS (71707, 90712, 93702)*

2.1 Operational Safety Verification

The inspectors observed overall plant operation and verified that the licensee operated the plant safely and in accordance with procedures and regulatory requirements. The inspectors conducted regular tours of accessible plant areas, including the following:

- Control Rooms
- Turbine Buildings
- Refuel Floors
- Reactor Buildings
- Control Buildings
- Switchgear Rooms
- Service Water Bays
- Protected Area Perimeter
- Access Control Points
- Diesel Generator Rooms

The inspectors observed plant conditions through control room tours; verified proper alignment of engineered safety features; verified operator response to alarm conditions was in accordance with plant operating procedures; verified Technical Specifications compliance, including implementation of appropriate action statements for equipment out of service; and reviewed logs and records to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, and system safety tags.

The inspectors conducted detailed walkdowns to inspect major components and systems for leakage, alignment, lubrication, cooling water supply, and general conditions that might prevent fulfillment of their safety function. The inspectors observed plant housekeeping, including control and storage of flammable material and other potential safety hazards.

The inspectors found that shift turnovers were comprehensive and accurate, and adequately reflected plant activities and status. Control room operators effectively monitored plant operating conditions and made necessary adjustments. Housekeeping was commensurate with ongoing work. The inspectors concluded that NMPC conducted overall plant operations in a safe and conservative manner.

2.2 Pressure Isolation Valve Leakage

In response to recent problems experienced at other nuclear power plants involving increased leakage past pressure isolation valves from the high pressure reactor coolant system (RCS) into low pressure systems (example: residual heat removal), the inspectors reviewed both units for the potential to operate in a similarly degraded condition.

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* The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

Unit 1

Low pressure core spray (LPCS) is the only major system with significant potential for an intersystem loss of coolant accident (ISLOCA) at Unit 1. The inspectors independently reviewed the associated piping and instrumentation drawing (P&ID #C-18007-C), determining parameters that would be available to identify any leakage from the RCS to the LPCS; specifically, pump discharge pressure indication (control room) and keepfill pressure indication (locally). The inspectors then discussed the potential for an ISLOCA with the control room staff, and the significance associated with the LPCS system. The operators confirmed the pressure indications as valid warning signs of leakage; additionally, the operators periodically monitor piping temperatures and area radiation monitors during their rounds. The inside containment isolation valves are normally closed, and the outside containment isolation valve is normally open. Keepfill taps into the LPCS system upstream of the outside isolation valve and downstream of a check valve. The inspectors walked down the accessible portions of the LPCS system, checking the pressure readings and monitoring the piping temperature; the inspectors determined that there was no discernible leakage into the LPCS system at that time.

Unit 2

There are two major systems at Unit 2 which are susceptible to ISLOCA, LPCS and residual heat removal (RHR). Using the P&ID for LPCS (PID #32A-10), the inspectors determined that the pump discharge pressure indication in the control room would best aid in the identification of leakage into the LPCS system, this was confirmed during discussions with the on-shift control room operators. From the control room indication, and from system walkdown, the inspectors confirmed that there was no discernible leakage into the LPCS system.

Similar pump discharge pressure indications for both divisions of the RHR system showed pressures of about 300 psig; expected pressure would be about 85 psig (equal to the discharge of the keepfill pump). However, a walkdown of the system did not identify any piping warm to the touch, indicative of a significant leak. RHR at Unit 2 has a history of intersystem leakage; specifically, past valves associated with the steam condensing mode of operation. During the last outage, these valves were worked on to minimize leakage past them and passed leakage tests. The operating procedure for RHR (N2-OP-31) has a section for venting of the system to reduce the pressure. A review of the alarm response procedures for high RHR pressure identified that division 2 RHR directs the operators to the operating procedure for guidance on venting the RHR system; however, the division 1 alarm response procedure does not contain this guidance. Also, during the walkdown of the system, minor deficiencies were identified by the NRC; these were discussed with operations department supervision. NMPC is reviewing the operating and alarm response procedures associated with the RHR system, and is performing further evaluation to determine if the pressure in the RHR system is due to valve leakage. This item will remain open pending NMPC's resolution. **(URI 50-410/94-03-01)**

2.3 Unit 1 Average Power Range Monitors

Due to detector problems, 4 of 8 of the Unit 1 intermediate range monitors (IRMs) are in standby while the remaining IRMs are operable. Although the inspectors were not concerned specifically about the IRMs being inoperable, there was concern because of a coincidence scram circuit that uses inputs from both the IRMs and the average power range monitors (APRMs).

Reference the attached drawing (typical of four channels per trip system).

During normal power operations:

- the four contacts marked with an asterisk are closed,
- the IRM Upscale and Inop are closed, and
- the IRM and APRM bypass contacts are open.

Thus, the associated scram relay is kept energized. Specifically, the IRM upscale scram function (greater than 95% of full scale) is in parallel with the APRM downscale scram function (less than 5% of full scale). An IRM that is in standby causes the IRM Inop contact to open, enabling the associated APRM to generate a half-scram signal if the indication falls below 5% of full scale; the four IRMs that are in operate basically bypassed that scram signal. The inspectors questioned the appropriateness of 4 of 8 of the APRM channels having one of the Technical Specification scram functions apparently bypassed during power operations while the other 4 channels have enabled the downscale scram function.

Unit 1 TSs require the IRM upscale and the APRM downscale trip functions to be operable when the reactor mode switch is in the RUN position. The initial purpose of this coincidence circuit was to ensure the operators maintained an indication of reactor power during startup. An associated note states that the IRMs are bypassed when the APRMs are onscale and the APRM downscale is bypassed when the IRMs are onscale. The note was confusing and allowed for different interpretations. The inspectors initially determined that the APRM downscale scram function should be enabled based on review of the TS bases, related deficiency/event reports (DERs) and safety evaluations, comparison to instrumentation of other plants of similar vintage, and discussions with NMPC engineering and operations personnel. In May 1992, NMPC initiated a DER due to the accelerated failure of IRM detectors; the IRM detectors were partially inserted into the reactor to ensure an upscale indication that would cause the IRM upscale contact to open, thereby enabling the APRM downscale scram function. The final disposition of the DER stated that the IRM should be fully withdrawn (as recommended by the vendor), this would cause the IRMs to indicate onscale. Thus the APRM downscale scram function would be bypassed. The safety evaluation did not provide an adequate justification for the change in operating philosophy.

After further discussions, the inspectors concluded that the APRM downscale scram function was not expected to be enabled during power operation, but was only required during reactor

startup. However, the safety evaluation did not provide adequate justification for the change in the Unit 1 operating practices with regards to the coincidence circuit. Unit 1 management agreed and initiated actions to revise the safety evaluation. This item will remain unresolved pending NRC review of the revised safety evaluation. **(URI 50-220/94-03-02)**

2.4 Unit 1 Spent Fuel Pool Cleanup

The inspectors monitored the activities on the Unit 1 refuel floor associated with the removal of miscellaneous irradiated hardware from the spent fuel pool. NMPC contracted with Waste-Chem to segment the components such that the pieces would fit into casks for shipping to a burial site. This activity was, by necessity, in areas of high-radiation levels, and caused high-airborne activity. The NMPC refuel floor coordinator (RFC) conducted thorough pre-job briefings and the health physics technicians (HP) performed frequent surveys to support the concept of ALARA (as low as reasonably achievable). HP personnel were on the refuel floor during all work periods, and the RFC was present during critical portions. The inspectors concluded that the evolution was completed smoothly and safely due to the close coordination of NMPC personnel with the contractors and the constant presence of HP.

However, several weaknesses were observed during the inspector's time on the refuel floor: material stored on the refuel floor was not completely consistent with the posted storage permits, and a Waste-Chem contractor assisted as a second signalman during crane operations, although not qualified by NMPC. The inspectors discussed the weaknesses with the RFC and DERs were initiated to resolve the weaknesses. The inspectors had no further questions.

3.0 MAINTENANCE (60710, 61726, 62703, 90700, 90712)

3.1 Maintenance Observations

The inspectors observed maintenance activities to ascertain if safety related activities were being conducted according to approved procedures, TSs, and appropriate industry codes and standards. Observation of activities and review of records verified that: required administrative authorizations and tag outs were obtained, procedures were adequate, certified parts and materials were used, test equipment was calibrated, radiological requirements were implemented, system prints and wire removal documentation were used, and quality control hold points were established. Maintenance activities observed included:

Unit 1

WO-94-00388-04	Eastern Cooler Piping Oil Leak [repairs to the T-2 transformer]
WO-94-00833	Repair Packing Leak at Root Valves to Reactor Vessel Level Transmitter 36-03C
WO-94-00157	Troubleshooting APRM 15

WO-93-04945	Spent Fuel Pool Cleanup; Including Processing, Packaging & Shipment of Irradiated Hardware

Unit 2

N2-IPM-GEN-@001	Safety Related Loop Calibration for Fuel Oil Storage Tank Level
EPM-GEN-V551	600V breaker 2EJS*US3-8C preventive maintenance
MPM-HVR-V557	Division II control building chiller preventive maintenance
WO 20-21502	2EJA*PNL301B molded case circuit breaker replacement
WO 94-00498	Troubleshoot single rod scram during weekly surveillance
WO 94-00288	RCIC steam supply drain line modification
WO 94-00485	Troubleshoot/repair radiation monitoring flow control system
WO 20-21525	Feedwater pump "C" new seal assembly and installation

The above activities were effective with respect to meeting the safety objectives.

3.2 Unit 2 Reactor Protection System Wiring Discrepancy

During performance of the weekly reactor protection system (RPS) manual scram channel functional test, a single control rod (#26-23) scrammed unexpectedly when operators inserted a half scram on channel B1. The Unit 2 station shift supervisor initiated a DER and the subsequent investigation revealed a blown "B" fuse for the control rod. The RPS consists of two independent, functionally identical trip systems (A and B) with each trip system divided into two independent, functionally identical trip channels (A1, A2; B1, B2). A scram pilot valve with two solenoids is provided for each control rod. When both scram pilot valve solenoids are deenergized, the scram pilot valve opens causing the scram inlet and outlet valves to open, thus scramming the control rod. By design, the A1/A2 trip logic controls the "A" scram pilot valve solenoids [in each of the rod groups] and the B1/B2 logic controls the "B" scram pilot valve solenoids. One-out-of-two-taken-twice logic is employed, requiring actuation of trip logic A1 or A2 and B1 or B2 to deenergize the "A" and "B" solenoids, respectively, for a scram to occur. Therefore, a single rod scram following insertion of a "B" trip system half scram would typically indicate a blown "A" fuse – this was not the case.

Electrical maintenance troubleshooting identified a wiring discrepancy at the hydraulic control unit (HCU) for rod 18-03. Specifically, two pairs of wires were interchanged at the HCU terminal block which caused the south side group four scram pilot valve solenoids to be controlled and powered by the opposite trip system. HCU 18-03 is the first of 24 HCU's for this parallel-wired HCU group and thus this wiring deficiency affected the remaining HCU's, one of which was HCU 26-23. The "A" fuses continue to remove power from the "A" solenoids and the "B" fuses remove power from the "B" solenoids (which is the case for all rods), but the trip system power supply to the fuses has been reversed. Therefore, with the "B" fuse blown deenergizing the "B" solenoid, the inserted half scram on channel B1 deenergized the "A" solenoid resulting in the single rod scram.

NMPC's investigation determined that rod 26-23 scrammed because of the blown fuse. However, the cause of the blown fuse could not be determined; this is the sixth RPS fuse failure at Unit 2 since 1989. A previously performed root cause evaluation for the fifth blown fuse could not conclusively identify a failure mechanism (system engineering personnel believe the failures may be related to age fatigue). Additionally, the engineering fuse design review concluded that the fuse specifications were acceptable for the RPS application. Further NMPC discussions with the vendor and an industry review of similar failures indicated that Unit 2's failure rate was consistent with the industry failure rate and the vendor recommended no additional corrective actions. Based on the above review and this recent event, NMPC continues to pursue the blown fuse issue and possible corrective actions.

The single rod scram event led to the discovery of the wiring error at HCU 18-03. Immediate corrective actions for this event included initiation of the DER and completing an operability determination for the wiring discrepancy. The long term corrective actions include completing a root cause evaluation, correcting the wiring error prior to the completion of the next refueling outage, and initiating a temporary modification to properly document and evaluate the condition.

The inspector performed the following to evaluate the RPS wiring error and the single rod scram: observed the discussions, troubleshooting, and investigation related to the wiring discrepancy; interviewed several individuals involved in the event investigation; reviewed the troubleshooting data, RPS design documentation, and associated electrical prints to independently confirm NMPC conclusions; reviewed the temporary modification package documenting the wiring discrepancy and the associated 10 CFR 50.59 safety evaluation; and reviewed previous Unit 2 single rod scram events.

Based on the above, the inspector agreed with NMPC's conclusion that the RPS function is not adversely affected by the reversed wiring at the group four HCU's or the blown fuse. Two separate power sources controlled by two separate trip systems continue to feed each control rod HCU. The corrective action evaluation for the blown fuse and the root cause evaluation for the wiring error; however, are incomplete. Therefore, this issue will remain unresolved pending completion of these evaluations and further NRC review.
(URI 50-410/93-03-03)

After the end of the inspection period, Unit 2 scrammed due to a faulty switch in the turbine protection circuitry. NMPC management corrected the RPS wiring discrepancy before the plant was returned to power operation.

3.3 Unit 1 Reactor Vessel Level Instrumentation Repairs

On March 1, control room operators noticed a two inch level difference between the channel #11 and channel #12 reactor vessel level indications. Data review determined previous level readings were the same. Operators were dispatched to check local Yarway indicators,

remote shutdown panel indicators, and the analog transmitter system (ATS) cabinet readings. Review of all level readings determined consistency with the two inch control room difference. The I&C technicians dispatched to the East instrument room identified level transmitter test connection valve packing leakage which resulted in increased flow in the level reference leg, causing higher reference leg temperatures and thereby providing a slight difference in level indication. The operations department initiated a high priority work order for the I&C department to adjust the valve packing to correct the leakage. The inspectors reviewed the work package and the guidance given to the I&C technicians from the shift supervisor. The inspectors concluded the maintenance task was adequately controlled and potential plant impact resulting from the packing adjustment was fully understood by the technicians. The technicians successfully stopped the leakage and subsequent monitoring of the reference leg temperatures and level indicators determined all indicators returned to normal. In addition, the SSS initiated a deficiency event report to review the event. The inspectors considered the timely corrective actions by the operations and maintenance personnel to be appropriate.

3.4 On-Line Leak Repair of Unit 1 Main Transformer

During the inspection period, the inspectors reviewed the activities related to the repair of the Unit 1 main transformer (T-2). One of the oil cooler lines was leaking at a flange, and earlier repairs using Furmanite had been unsuccessful. The inspectors reviewed the work package (WO 94-00388-04) for repairs using a different leak sealant, Belzona. NMPC performed a 10CFR50.59 safety evaluation for Belzona MP Fluid Elastomer #2221, considering possible ramifications of the two sealants coming in contact with, and the affect weight of the containment box on the piping. In addition, an environmental analysis was performed for Belzona, with a one-time use allowed on the Chemical Approval Request.

The inspectors observed the preparation and application of the Belzona. Maintenance procedure N1-MMP-GEN-02, "On-Line Leak Sealing of Flange & Packing Leaks," provided adequate guidance to the mechanics for use of the leak sealant; including appropriate personnel safety precautions and notes as to the use of the sealant. The work package and the actual maintenance were in accordance with management expectations, as delineated in nuclear division directives.

3.5 Unit 2 Maintenance Backlog

The inspector reviewed the Unit 2 power block maintenance backlog, both outage and non-outage, to determine whether NMPC management afforded sufficient priority to safety-related maintenance and to confirm that significant maintenance backlogs did not exist for safety-related systems. Power block systems are primarily those associated with the safe and reliable generation of electricity. As part of this review, the inspector performed the following: reviewed the 1993 and 1994 nuclear division business plans and the 1994 branch business plans for maintenance, outage/work control, and technical support (branch business plans implement the division business plan); compared the 1993 and 1994 nuclear business

plan performance indicator goals to the actual backlog numbers; interviewed Unit 2 staff personnel on the backlog numbers, the backlog philosophy, and the methods being used to focus attention on and reduce the backlog; reviewed both the outage and non-outage power block backlogs; performed a partial field verification of the outstanding corrective maintenance items for the control room, the high pressure core spray system, and the reactor core isolation cooling system to determine the safety significance; attended maintenance planning meetings; and interviewed Unit 2 operators on the impact of certain plant deficiencies.

In 1993, Unit 2 tracked two business plan performance indicators related to the maintenance backlog: non-outage power block backlog and percentage of power block work orders on hold for materials, with target goals of 500 items and 6 percent, respectively. Throughout the year, Unit 2 met the goals for these performance indicators. However, the total non-outage backlog, which only included the corrective maintenance work orders, increased as the 1993 refueling outage approached and during the outage.

For 1994, NMPC changed the business plan performance indicators related to the maintenance backlog to the percentage of non-outage backlog greater than 90 days old and the number of non-outage control room deficiencies greater than six weeks old. Year-end target goals are 25 percent and 25, respectively. In addition, the definition of non-outage backlog was significantly expanded to include both work orders and problem identifications for corrective maintenance, rework, and troubleshooting. Plant management considered these changes necessary to more accurately reflect the existing plant deficiencies, provide a better measurement of backlog management, and to focus greater attention on control room deficiencies.

At the end of the inspection period, 68 percent of the non-outage backlog was greater than 90 days old with a total non-outage backlog of 791 corrective maintenance items. These numbers were consistent with the 1993 numbers after accounting for the changes in the performance indicator definitions. The 68 percent backlog indicator emphasized the long standing corrective maintenance items and the challenging business plan goal. However, the trends indicate that new corrective maintenance items were added at about the same rate that existing items were removed. Although corrective maintenance work orders were scheduled for completion at a rate that would ultimately achieve the business plan goal, the completion rate for the scheduled work orders was low (50 to 60 percent). Frequently, the work packages are not ready for the field, and sometimes the work is just not completed. The inspectors concluded that the Unit 2 effort has not been effective at reducing the long standing corrective maintenance backlog.

One other area for improvement with respect to the backlog is the high ratio of problem identifications (PIDs) to the total backlog, about 45 percent. PIDS are plant deficiencies that are awaiting disposition via work orders, modifications, etc. Even though all PIDs are initially reviewed for plant impact by the station shift supervisor and the operations department planning staff, the full work scope is typically not identified until a work order is

generated. The high number of outstanding PIDS waiting to be dispositioned creates a vulnerability for inefficient planning and completion of corrective maintenance.

Unit 2 has exceeded the business plan goal for control room deficiencies, with only 14 deficiencies greater than six weeks old from a total of 22 non-outage deficiencies and an additional 14 outage related deficiencies. This excellent achievement directly resulted from a plant-wide heightened awareness of control room deficiencies and their impact on the plant operators.

In summary, the inspector concluded that NMPC actively managed the safety-related maintenance backlog, set challenging goals for the corrective maintenance backlog reduction, and demonstrated the proper safety perspective when prioritizing plant maintenance. In addition, Unit 2 personnel made a significant commitment to reduce the challenges to control room operators by prioritizing the control room deficiencies and nearly achieving a "black board" at the end of the inspection period. However, two areas for improvement were noted with respect to the ratio of scheduled corrective maintenance work orders to completed work orders and the ratio of PIDs to the total backlog.

3.6 Review of Troubleshooting Activities

The inspectors reviewed GAP-PSH-01, "Work Control," and concluded that adequate administrative controls were in place for the development and performance of maintenance work orders (WOs). The inspectors noted good administrative controls established for troubleshooting activities, as described in section 3.4, of GAP-PSH-01. In general, the inspectors found that troubleshooting performed by the maintenance department is controlled by the maintenance work order process and the related administrative controls. Troubleshooting task plans include the following in work instructions to craft personnel:

- enough detail to ensure an SSS fully understands intended evolution and plant impact;
- identification of temporary alterations made to the system, structure, or component; and
- adherence to technical requirements.

Each troubleshooting task and associated plant impact was verified as accurate by an independent reviewer knowledgeable of the work to be performed. An SSS authorized each troubleshooting plan prior to performance. Any necessary revisions to troubleshooting steps were approved by the SSS and documented on the WO prior to being performed. Review of troubleshooting activities by the inspectors determined the above work instructions have been followed and the implementation of the troubleshooting process appears to ensure adequate control and documentation of troubleshooting activities. Recent troubleshooting activities reviewed by the inspectors included:

- WO-94-00157 Troubleshooting APRM 15 (Unit 1)
- WO-94-00833 Repair Reactor Vessel Level Indicator Difference (Unit 1)
- WO 94-00498 Troubleshoot single rod scram during weekly surveillance (Unit 2)

- WO 94-00485 Troubleshoot/repair radiation monitoring flow control system (Unit 2)

3.7 Surveillance Observations

Through observation of safety-related surveillance activities, interviews, and review of records, the inspectors verified: use of proper administrative approve, personnel adherence to procedure precautions and limitations, accurate and timely review of test data, conformance of surveillances to TSs, including required frequencies, and use of good radiological controls. Surveillance activities observed included those listed and discussed below:

Unit 1

N1-ST-C5	Secondary Containment and Reactor Building Emergency Ventilation and System Operability Test
N1-RSP-11Q	Service Water Discharge Radiation Monitors Test
N1-ST-Q25	Emergency Diesel Generator Cooling Water Quarterly Test
N1-ISP-092-210	IRM Rod Block and Scram Instrument Channel Functional Test
N1-ISP-092-204	IRM Instrument Calibration

Unit 2

N2-CSP-EDG-M500	Emergency Diesel Fuel Monthly Particulate Surveillance
N2-OSP-EGS-M001	Diesel Generator and Diesel Air Start Valve Operability Test - Division 1 & 2
N2-ESP-BYS-R682	Division II Battery Charger Load Test (for 2BYS*CHGR2B2)
N2-OSP-RPS-W002	Manual Scram Channel Functional Test
N2-OSP-GSN-Q002	Nitrogen System Check Valves Exercise Test

The above activities were effective with respect to meeting the safety objectives.

3.8 Nitrogen System Check Valve Testing

The inspectors observed portions of N2-OSP-GSN-Q002, Nitrogen System Check Valves Exercise Test, and reviewed the completed surveillance procedure. Unit 2 performed this surveillance as part of the quarterly TS and ASME Code required in-service test program for the nitrogen supply check valves to the automatic depressurization system. The operators performing the surveillance demonstrated excellent system knowledge and used proper communication techniques. The inspector considered all aspects of the surveillance satisfactory with one exception relating to independent verification requirements.

Specifically, a licensed operator performed several procedural steps without obtaining an independent verification prior to continuing to the next step. After discussion with the inspector, the operator discussed the issue with the SSS and initiated a DER. Operations

department management promptly reviewed the issue and initiated a root cause evaluation. The inspectors considered NMPC's actions acceptable and noted that the failure to obtain an independent verification had minor safety significance in this instance.

4.0 ENGINEERING (37700, 40500, 71707, 90700, 90712)

4.1 Water in the Unit 1 Cable Spreading Room

On February 21, operators discovered a pool of water in the Unit 1 cable spreading room (turbine building, 250 foot elevation, southeast corner). Over 1000 gallons of ground water leaked into the room, through electrical penetrations. The floor drain in the immediate area was partially clogged, causing the water to cover an area approximately 20 feet in diameter and 6 inches deep. Personnel utilized a nearby drain to remove the water. This same penetration leaked last year; at that time, new sealant was applied to prevent further leakage. NMPC initiated two DERs to evaluate the effect of the water on the electrical cables and to determine alternate means of minimizing the influx of water into the buildings.

The inspectors toured the areas to determine the extent of the damage caused by the leakage. Other than cables suspended about four feet above floor level, there is no other equipment in the room. There was no obvious damage to the cables or the cable tray. However, it was noted that water was still seeping through the cable penetrations, traveling along the cables and collecting in the base of the cable tray. The inspectors questioned (1) what systems or controls were routed through the penetrations, (2) whether the cables were qualified for submergence in water, (3) what is the condition of the cables on the other side of the penetration [inaccessible], and (4) why didn't the previous corrective action eliminate the problem? Pending resolution to the these questions, this will remain an unresolved item. **(URI 50-220/94-03-04)**

4.2 Unit 1 Torus and Main Condenser Water Box Corrosion

NRC inspection report 50-220/92-01 detailed a review of the torus and main condenser water box corrosion monitoring programs and the independent NRC ultrasonic thickness measurements. During that inspection NMPC committed to inform the NRC of future torus and condenser water box inspections to allow the NRC the opportunity to perform additional independent measurements. Based on subsequent NRC inspections and the ongoing corrosion monitoring program, the NRC no longer requests that this information be provided on a periodic basis. The NRC will continue to review NMPC's inspection results during routine inspections.

5.0 PLANT SUPPORT (60710, 71707, 90700, 90712)

5.1 Radiological and Chemistry Controls

During routine tours of the accessible areas at both units, the inspectors observed the implementation of selected portions of NMPC's radiological controls program to ensure: the utilization and compliance with radiological work permits (RWPs), detailed descriptions of radiological conditions, and personnel adherence to RWP requirements. The inspectors observed adequate controls for access to various radiologically controlled areas (RCAs) and use of personnel monitors and frisking methods upon exit from these areas. Posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with NMPC procedures. Radiation protection technician control and monitoring of these activities was satisfactory. Overall, the inspectors observed an acceptable level of performance and implementation of the radiological controls program.

5.2 Security and Safeguards

The inspectors observed implementation of the physical security plan in various plant areas with regard to the following: protected area and vital area barriers were well maintained and not compromised; isolation zones were clear; personnel and vehicles entering and packages being delivered to the protected area were properly searched and access control was in accordance with approved licensee procedures; persons granted access to the site were badged to indicate whether they have unescorted access or escort authorization; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and written procedures were available; and adequate illumination was maintained. Licensee personnel were observed to be properly implementing and following the physical security plan.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707)

6.1 Review of Licensee Event Reports and Special Reports

The inspector reviewed the following licensee event reports (LER) and special reports to verify that they conformed to the requirements specified in 10 CFR 50.73 and TSs. These requirements include a proper narrative description of the event, the cause of the event, an assessment of the safety consequences, and corrective actions.

LER 50-220/94-01: Violation of T S Surveillance Requirements Caused by Cognitive Personnel Error

On January 6, 1994, NMPC determined that Unit 1 violated Technical Specification (TS) surveillance requirements; i.e., prior to reactor restart on August 9, 1992, Unit 1

maintenance personnel failed to properly calibrate intermediate range monitors (IRMs) as required by TS requirements 4.6.2.a(9) and 4.6.2.g(2). Similar errors were subsequently repeated five times between September 3, 1992 and April 14, 1993. Further NMPC review determined that Unit 1 committed the same error for the source range monitors (SRMs) at the same time, as required by TS requirement 4.6.2.g(1). The TS require a calibration of the SRM and IRM instrument channel scram and rod block trip functions prior to each startup and normal shutdown.

In order to understand the event, the following background information is provided. Following an August 1992, scram of the Unit 1 reactor, senior NMPC management requested an evaluation of the lengthy IRM and SRM calibration process. Based upon limited information, the maintenance manager initiated a procedure change to revise the calibration procedure frequency to every two years, consistent with similar plant practices. NMPC performed an inadequate safety review to support this procedure change in that no technical or licensing basis was developed to support the change. The calibration procedures require the input of a simulated signal to verify the setpoint for each of the the trip functions. The weekly channel test procedures ony determine if the trip function occurs, but does not verify the setpoint. The channel test does not satisfy the TS requirements for calibration.

NMPC completed a thorough review of this event and concluded that the IRMs were capable of performing their safety function. Channel test procedures performed prior to startup and normal shutdowns for the period between August 1992 and April 1993 verified the upscale trip function. These facts provide reasonable assurance that the IRM upscale trip setpoints remained within calibration tolerances during the period of time Unit 1 failed to perform this required calibration.

It is noted that the surveillance testing performed by NMPC during the period of August 1992 through April 1993 is consistent with standard TS frequencies and specific allowances allowed by similar plants' TSs. However, this does not alleviate NMPC from their responsibility to meet existing channel calibration surveillance requirements. The licensee's immediate corrective actions included restoring the previous calibration process to meet the TS surveillance requirements for SRM and IRM calibrations. Other corrective action included intensive coaching and counseling with department supervisors involved in the procedure change. NMPC attributed the root cause of the event to a misinterpretation of the TS surveillance requirements and an improper approval of a change to the SRM and IRM calibration procedures.

This item was licensee identified and corrective actions were taken prior to the end of this report period. The safety significance of the missed surveillance tests is low based on the surveillance tests performed; there is reasonable assurance that the SRMs and IRMs were operable and would have performed their design functions. This violation will not be subject to enforcement action, in accordance with 10 CFR 2 Section VII.B(2), because it was

licensee identified, it is not a repetition of a previous violation, corrective action was initiated within a reasonable time, and it was not willful. This LER is closed.

Unit 2 Special Report dated January 31, 1994

The inspectors reviewed a special report submitted pursuant to Unit 2 Technical Specifications. The report discussed the inoperability of the stack gaseous effluent monitoring system (Stack GEMS). On January 16, while operating at 100% power, NMPC declared the Stack GEMS inoperable when the sample line became frozen due to sustained low outdoor temperatures reaching -11°F. The appropriate compensatory measures were taken while the system was out of service. Additional heat tracing was installed and the system was returned to an operable status on January 21, 1994. The inspectors assessed that the report contained the required information and clearly defined the cause of the event and the corrective actions.

Unit 1 Special Report dated February 2, 1994

The inspectors reviewed a special report submitted pursuant to Unit 1 Technical Specifications. The report discussed the inoperability of the #11 containment hydrogen monitoring system (HMS). On January 19, while operating at 100% power, NMPC removed the #11 HMS from service due to bypass flow out of specification. The #12 HMS remained in service. The cause of the low flow was determined to be a degraded sample pump, due to normal wear; also, a small leak was found in an instrument line. The pump and instrument line were repaired, but the flow was still erratic. Additional troubleshooting identified problems with the stream selector valve actuators and the stream regulators. New actuator couplings were installed and the regulators were rebuilt. System calibration was completed on February 15, and #11 HMS was returned to an operable status. The inspectors assessed that the report contained the required information and clearly defined the cause of the event and the corrective actions.

6.2 Minor Personnel Performance Problems

This inspection report details, at both units, examples of personnel performing activities not in accordance with approved procedures. Sections 2.4 and 3.8 discuss instances identified by the inspectors of failure to follow procedural requirements. This performance is not consistent with Nine Mile management expectations. Each case is of minor safety significance by itself; but combined, there is a trend of inattention to detail. In each case, NMPC management initiated timely and appropriate corrective action.

6.3 Station Operations Review Committee Meetings

The inspectors attended several Station Operations Review Committee (SORC) meetings for each unit and joint meetings. A combination of assigned members and allowed alternates comprised each meeting. SORC members discussed proposed DER dispositions and 10 CFR 50.59 safety evaluations, discussions focused on safety and corrective actions.

7.0 PREVIOUSLY IDENTIFIED ITEMS (92701)

(Closed) URI 50-410/93-25-01
Independent Safety Engineering Group Review

The Unit 2 Technical Specifications require the Independent Safety Engineering Group (ISEG) to make detailed recommendations for revised procedures, equipment modifications, and other activities to improve unit safety. Although ISEG reports contain numerous recommendations, no system was being used to effectively track the recommendations to closure.

In response to this item, ISEG developed a data base for tracking recommendations. ISEG reports since 1990 were reviewed to identify all recommendations. Each recommendation was entered into the data base with a unique file number, a responsible department for action, and a short description of the recommendation. Each recommendation was then assigned to an ISEG member to determine if the recommendation had been acted upon. Possible scenarios included: the recommendation was accepted and implemented satisfactorily, the recommendation was accepted but not implemented satisfactorily, or the recommendation was not accepted.

The inspectors performed an independent sampling of reports and found that all recommendations were entered into the data base, and that the information was accurate. The inspectors also reviewed the assignment sheet for each item to review the progress on closing the recommendations. The inspectors identified some weaknesses in the closure process used by some of the ISEG members. These weaknesses had also been identified by the Director, ISEG, during his review of the sheets. NMPC's action to date were adequate, this item is closed.

8.0 MANAGEMENT MEETINGS

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of this inspection. Based on the NRC Region I review of this report and discussions held with Niagara Mohawk representatives, it was determined that this report does not contain safeguards or proprietary information. NMPC did not object to any of the findings or observations presented at the exit meeting.

ATTACHMENT 1