U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Docket Nos.:	50-220; 50-410
License Nos.:	DPR-63; NPF-69
Licensee:	Niagara Mohawk Power Corporation 301 Plainfield Road Syracuse, New York 13212
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	November 1 through December 12, 1992
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Inspection Summary: This inspection report documents routine and reactive inspections of plant operations, radiological controls, maintenance, surveillance, emergency planning, security, and safety assessment/quality verification activities.

Results: See Executive Summary.

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2

NRC Region I Inspection Report Nos. 50-220/92-25 & 50-410/92-29

11/01/92 - 12/12/92

Plant Operations

Both of the units were operated safely over the period. Operators at Unit 2 did an excellent job in response to a failed reactor protection relay and in response to the subsequent reactor scram.

Radiological Controls

The implementation of the radiological control program was observed to be satisfactory over the period.

Maintenance and Surveillance

Maintenance and surveillance activities conducted at both units were observed to be generally well conducted. The maintenance organization responded well when a maintenance technician removed the wrong drain plug from an emergency diesel generator heat exchanger causing a small contained spill of chromated coolant. At Unit 2, a gauge with the wrong range was installed on the 1B standby liquid control pump suction during surveillance testing. This issue was not technically significant, since the gauge was digital and should have had sufficient accuracy. However, the persons verifying calibration, installing and using the gauge did not identify and correct the problem, or did not notify the inservice testing department and complete a procedure change as required by the surveillance test. For this reason, and because of previous problems with the use of improperly ranged gauges during surveillance testing, a violation was issued.

Emergency Planning

During the period, the 1992 partial-participation emergency drill was conducted. The drill had to be suspended for several hours to allow the site staff to respond to the reactor scram at Unit 2.

Executive Summary (Continued)

Engineering and Technical Support

Review of a 10 CFR 2.206 petition to shutdown Unit 1 was conducted with respect to a provided list of primary containment and reactor coolant system isolation valves. The inspector found that the valves specified on the list were properly addressed as not needing testing or were being tested according to the IST plan, the technical specifications, and the UFSAR.

Security

The inspectors observed that the security force properly implemented the observed portions of the security plan.

Safety Assessment/Quality Verification

The post-trip review process functioned well following the November 4 reactor scram. Plant management used good safety perspective and ensured that problems were addressed prior to plant restart. A Safety Review and Audit Board meeting was attended and found to provide good review and oversight of site activities. A review of the 1992 Licensee Event Reports (LERs) indicated that the failure to properly assess plant impact was a common contributor to nine separate events.

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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.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

1.1 Niagara Mohawk Power Corporation Activities

The Niagara Mohawk Power Corporation (NMPC) operated Nine Mile Point Unit 1 (Unit 1) safely, essentially at full power over the period.

NMPC operated Nine Mile Point Unit 2 (Unit 2) safely, essentially at full power, until a November 4 reactor scram. The scram resulted from the failure of a normally energized relay in the reactor protective system (RPS). NMPC completed their review of this event on November 6 and restarted the unit on November 7. Operators increased reactor power to 100% and safely operated the unit through the remainder of the period. On November 15, one of the two offsite power lines was de-energized due to an equipment failure in its supply breaker, located in the Scriba switchyard.

1.2 NRC Activities

Resident inspectors conducted inspection activities during normal, backshift and weekend hours over this period. There were 12 hours of backshift (evening shift) and 7 hours of deep backshift (weekend, holiday, and midnight shift) inspection during this period.

During the week of December 7 a routine inspection of the environmental monitoring program was conducted. The findings of this inspection will be documented in Combined Inspection Report 92-28/33.

From November 3-5 the routine partial participation emergency preparedness inspection was conducted. Combined Inspection Report 92-27/31 documents the observations and findings during the November 4 drill.

On December 1, a meeting was held with NMPC senior management in NRC Region I to discuss recent performance at both units. Attachment 1 to this report provides the list of attendees and the presentation material provided by NMPC.

1.2.1 NRC Receipt of Petition for Emergency Enforcement Action and Request for Public Hearing on Unit 1

On October 27, 1992, a petition was filed under 10 CFR 2.206, requesting that the NRC order NMPC to immediately cease power operation at Unit 1 and place the unit in a cold shutdown condition. The petition further requested that the NRC hold a public hearing before authorizing resumption of power operation. The basis for such an order and hearing

included concerns that: (1) the Unit 1 feedwater system operating in its high pressure coolant injection (HPCI) mode does not meet NRC requirements for an engineered safety feature systems (ESF) grade HPCI system; and (2) 45 percent of containment isolation valves have administrative deficiencies.

The NRC staff's initial review of this petition, documented in NRC letter dated December 4, 1992, to the petitioner, did not identify any need for an immediate order to shutdown Unit 1. With respect to the HPCI concern, initial staff review determined that the emergency systems met the NRC requirements for core cooling in accordance with 10 CFR 50.46. The feedwater system operating in its HPCI mode is not taken credit for in the 10 CFR 50, Appendix K analysis; but rather the automatic depressurization (ADS) and core spray (CS) systems are relied upon to depressurize the reactor and cool the core, respectively. While this mode of feedwater system operation is not an ESF grade system, it is required to be operable by technical specifications. The inspectors reviewed and observed portions of the quarterly surveillance testing on this system and found, as documented in section 5.1.2 below, that it adequately demonstrated the operability of the system. With respect to the concerns on administrative deficiencies on primary containment isolation valves, the staff found, based on the initial inspection documented in section 6.1.1 below, that minor deficiencies exist, but that valves were being properly tested to ensure proper operation of the isolation function. .

2.0 PLANT OPERATIONS (71707,93702)

2.1 Plant Operations Review - Unit 1

The inspectors observed good control of plant operations by the Unit 1 operations staff. Control room operators operated the plant safely. NMPC took a good initiative to increase the ability of the station shift supervisor (SSS) and the assistant station shift supervisor (ASSS) to supervise the other member of the operations crews by removing walls and rearranging their office space within the control room.

2.2 Plant Operations Review - Unit 2

The inspector observed good control of plant operations by the Unit 2 operations staff. Control room operators operated the unit safely and took appropriate actions to address problems such as the failed RPS relay discussed below. Operators were always aware of the reasons for annunciated alarms on control room panels.

2.2.1 Review of November 4 Reactor Scram

The inspector observed that the operating crew performed excellently during their response to the November 4 reactor scram. The ASSS performed very well as he carried out the emergency operating procedures and directed the activities of the crew. The SSS was also very effective at maintaining an overall assessment of plant conditions and provided proper oversight of the ASSS and the crew. The reactor operators and non-licensed operators performed well with respect to monitoring and controlling reactor vessel level and pressure using the feedwater, reactor core isolation cooling (RCIC), safety relief valve (SRV), and residual heat removal (RHR) systems.

While operating at 100% power, following half scram testing on the A RPS channel, operators detected smoke coming from one of the B RPS channel cabinets, in the back of the control room. The SSS opened the cabinet and observed smoke coming from what he thought was a normally energized B RPS relay, because of its location and lack of component identification tag. The SSS prudently ordered that the B RPS relays be de-energized by inserting a manual half scram of the B RPS logic. After the B RPS channel was de-energized the SSS determined, through discussion with operators and instrument and control (I&C) technicians, that the subject relay was actually powered from A RPS (although located in a B RPS cabinet), and thus had not been de-energized by placing the manual scram on the B RPS channel.

Before the SSS could order that the manual half scram be cleared from the B RPS channel and inserted on the A RPS channel, the power supply fuse to the affected relay failed. The blown fuse together with the B RPS half scram caused one-quarter of the control rods to be inserted, as designed. The insertion of these control rods caused reactor power to decrease from 100% to 14%, and reactor water level decreased due to the power transient to the low level scram setpoint within about ten seconds. At that point an automatic full scram occurred and all control rods were inserted.

Operators took effective actions to control reactor vessel water level and pressure. To limit the plant cooldown the main steam isolation valves were shut. Operators used RCIC, recirculating to the condensate storage tank and manual opening of SRVs to control reactor pressure, while the steam condensing mode of RHR was readied for operation. Communication between the SRV operator and the other operators controlling reactor vessel level with the feedwater system and the RCIC system was very good. The SRV operator noticed that one valve gave both an open and closed indication on the control panel when it was signaled to open. This valve was then shut and not used in the following SRV cycling sequence. During the SRV cycling, reactor water level changed up to 60 inches, with level swelling as the valve was open and shrinking when the valve was closed. These level changes caused several isolations of RCIC on high level and a second low level reactor scram.

The operations staff and plant management exhibited very good questioning attitudes during the post-scram review process and functioned well to ensure that issues needing resolution were completed prior to unit restart. The critique conducted by the reactor analyst supervisor was very good as operators were given the opportunity to discuss their observations and actions. This process lead to the identification and resolution of several issues that included the failure of the RPS relay, the SRV position indication problem, and reactor water level changes during the SRV operation. The inspector attended the pre-restart Site Operations Review Committee (SORC) meeting and found that all the issues necessary for restart were either dispositioned or tracked to allow disposition prior to restart. NMPC could not determine the cause for the RPS relay failure prior to startup, but did take thermographic pictures of the other similar relays and planned to incorporate this into a preventive maintenance (PM) schedule. The failed relay was replaced with an equivalent replacement relay. The inspector interviewed procurement personnel and reviewed the vendor's product quality certificate, NMPC's spare parts equivalency review and the quality control inspection reports for the replacement relay. All documentation for the replacement relay was satisfactory.

Good discussion was observed during the review of the repair for the SRV acoustic monitor SRV that did not have positive indication of position. Plant management took the necessary actions to ensure that the monitor was operable prior to startup. This included de-inerting the drywell and replacing a broken acoustic pickup.

The reactor water level swings observed during SRV operation were analyzed and determined to have been caused by actual fluctuation in the reactor level as the pressure of the coolant was changed, not due to gasses coming out of solution in the reference legs of the instruments.

The inspector reviewed the response of the RPS system to this event and found that it was according to the design. The reason for having RPS relays of the other division (A RPS relays in B RPS cabinets) was for 10 CFR 50, Appendix R fire considerations, to allow a backup scram to occur if fire damage to one RPS channel precluded its normally energized scram relays from opening.

NMPC submitted licensee event report (LER) 92-22, on December 4. This LER adequately discussed the event and the corrective actions taken. The LER stated that GE had provided the industry with information on potential failures of the type of relay that failed, but that the failure of this relay did not relate to GE's information. The inspector considered this LER open pending review of the GE information and PM program on these relays.

2.2.2 Partial Loss of Offsite Power

On November 15, with the unit operating at 100% power, offsite power line 5 was lost to Unit 2 because its offsite supply breaker (R50) inadvertently opened. The control room had no knowledge of problems with the offsite breaker before it opened. The Division I and III emergency diesel generators (EDG) started to supply power to their busses. Operators took appropriate actions by parallelling the EDGs with the remaining offsite power supply and then securing the EDGs. Initially operators could not parallel the Division I EDG with line 6 because the operators did not have speed control of the EDG when preparing to parallel. Operators identified a broken connector on the speed sensing probe and were able to parallel and secure the EDG (further corrective actions on this problem are discussed in section 4.2.2 below).

NMPC review of the R50 breaker indicated that it had tripped open on low nitrogen accumulator pressure in its operating mechanism. This nitrogen accumulator pressurizes the hydraulic operator for this breaker and is designed to trip open at a given low pressure setpoint. NMPC offsite maintenance determined that the shaft on the hydraulic pump, used to keep the pressure in the nitrogen accumulator and thus the hydraulic system, had failed. This caused the motor to run without the pressure being restored to normal. Preventive maintenance on this breaker and on the other offsite power breaker (R60) had been conducted within several weeks of this breaker failure. This failure was similar to a previous event that occurred when R60 opened due to low nitrogen pressure. In that case, control room operators had been previously told by the offsite maintenance crew that the breaker would not open if nitrogen pressure decreased.

The inspector toured the offsite switchgear and discussed the failures of the breakers with the offsite maintenance personnel. NMPC site management directed that the independent safety engineering group (ISEG) review the recent loss of offsite power and determine what action needed to be taken to limit these occurrences. This instance was the sixth time in several years that either a partial or complete loss of offsite power has occurred. NMPC submitted LER 92-23 documenting this incident on December 14, 1992. This LER remained open pending further inspection review of the corrective actions.

3.0 RADIOLOGICAL AND CHEMISTRY CONTROLS (71707)

3.1 Routine Observations - Unit 1 and Unit 2

The inspectors observed good use of radiological protection practices, proper use of procedures, and adherence to postings during routine plant tours.

4.0 MAINTENANCE (62703)

Inspectors observed and reviewed selected activities to verify that safety-related maintenance was conducted in accordance with approved procedures, technical specifications, and appropriate industrial codes and standards. Observations and reviews included verification of the proper use of: administrative authorizations and tag outs (including lifted leads), certified parts and materials, calibrated test equipment, proper radiological requirements, controlled drawings, and correctly established quality control hold points.

4.1 Observation of Maintenance Activities - Unit 1

4.1.1 Liquid Poison Loop 12 Pressure Tap Installation

The inspector observed portions of the installation of a pressure tap between the liquid poison pump 12 and its discharge check valve, to assist in quarterly system reverse flow testing. Both the mechanics and QA inspectors demonstrated proper quality control throughout the implementation of this simple design change. The welding technic and post-weld inspections were satisfactory. The mechanics performing the maintenance were very knowledgeable and performed the procedure properly, using good radiological work practices and proper cleanliness controls.

4.1.2 Emergency Diesel Generator Cooling Heat Exchanger Disassembly

Chemistry and maintenance technicians performed a routine quarterly inspection of EDG-102 cooling water heat exchanger 79-03. Partial disassembly of the cooler required draining the tube (raw water) side and removing the "floating head" at one end to gain visual access to the internal tubing. The maintenance procedure directed the technicians to drain residual water from the cooler head area by removing the drain plug on the underside of the assembly prior to unbolting the head flange. The procedure contained a diagram showing drain plugs on the underside of the cooler, but did not identify the specific internal areas that could be drained by each plug. The technician mistakenly removed a plug on the shell side of the cooler, draining approximately 15 gallons of potassium chromated jacket cooling water onto surrounding equipment and floor spaces before the drain plug was reinserted. The inspector observed other maintenance technicians in the diesel room respond quickly to contain the spilled water and to prevent a release of the liquid from the building. Environmental protection, fire department, operations, and other site organizations immediately responded to the diesel room to assess the potential consequences of this spill. All maintenance work in the diesel room was suspended until the cause of the incident was determined and corrective actions were taken to prevent a recurrence.

The inspector considered the critique conducted by maintenance to have fully addressed the incident and adequately identified the needed corrective actions, prior to resuming work. The primary corrective action was to revise the maintenance procedure by clearly labelling the different drain plugs on the heat exchanger housing. Maintenance supervisors considered

that close supervisory monitoring, additional training, and detailed pre-job briefings were not warranted for this task because of its relative simplicity. However, supervisors did advise other personnel of the procedure change and emphasized the specific locations of the different cooler drain plugs.

The inspector discussed with the system engineer potential operability consequences related to possible water intrusion on electrical components near the diesel coolers. A thorough inspection of the diesel fuel transfer pump, the lube oil pump, and the lube oil emersion heater was made by the system engineer and electrical maintenance technicians. No water had apparently entered these components. Also, no additional makeup to the jacket cooling water system was required since the expansion tank level was still in its normal band. No other diesel operability concerns were identified. All adjacent surfaces on the diesel equipment pallet were wiped to remove spilled liquid and all surrounding floor areas were thoroughly cleaned. The inspector considered that the licensee's overall response to this event was timely and appropriate.

When heat exchanger disassembly resumed, the inspector observed direct supervisory oversight in the work area. When the cooler internals were exposed, a site chemistry technician performed a visual inspection of and took samples for laboratory analysis from the internal head and tube areas. The inspector reviewed the inspection criteria contained in the procedure and independently verified that internal heat exchanger surfaces on the raw water side were in generally good condition, free from excessive corrosion and flow blockage, and that muscle shells or fragments were not present. Relatively small amounts of microbiologically-induced corrosion were present on the internal surface of the cooler head, but most of this material was removed when samples were taken. The inspector discussed the inspection methodology with the chemistry technician and found him to be very knowledgeable and experienced in this type of heat exchanger inspection. The technician made appropriate entries in the procedure to reflect his visual inspection. Samples for subsequent laboratory analysis were properly labeled.

Overall, mechanical maintenance technicians were knowledgeable of diesel heat exchanger construction and disassembly/reassembly requirements. They demonstrated adequate skill and attention to procedure requirements during reassembly of the heat exchanger. The inspector discussed with the maintenance supervisor the deficiency event report (DER) written to evaluate the cooling jacket water spill and considered that all factors associated with the event were properly identified and documented.

4.2 Observation of Maintenance Activities - Unit 2

4.2.1 Division II Emergency Diesel Generator Local Annunciator Failure Troubleshooting

The operations department and I&C technicians took conservative, timely and effective actions to evaluate and correct a loss of power to the local Division II EDG annunciators. During routine rounds on November 5, an operator found the local panel annunciators

inoperable. Further investigation revealed that the isolation breaker upstream of the three annunciator power supplies had tripped and would not reset. The operating crew conservatively declared the EDG inoperable and took appropriate actions in accordance with the technical specifications (TS).

The inspector observed the annunciator troubleshooting and return to service conducted by I&C technicians. The technicians identified a short circuit on the output of one power supply and properly questioned why the fuse upstream of that supply did not blow prior to the tripping of the upstream breaker. Further investigation identified that the three power supplies for the annunciators have a common output; vice supplying separate rows of annunciators as previously thought. Thus, with all three power supplies feeding the fault, the limit on the individual fuses was not exceeded, but the combined current was enough to trip the breaker. The failed power supply was replaced and the Division II EDG was returned to operable status. NMPC initiated a DER to evaluate the adequacy of this design.

4.2.2 Division I Emergency Diesel Generator Speed Control Failure

The inspector determined that the operations and I&C departments aggressively pursued returning the Division I EDG to service following failure of the speed sensor discussed in section 2.2.2 above. The inspector reviewed the work conducted and discussed the troubleshooting effort with the system engineer and the SSS. A broken connector on the speed sensor caused the lack of control. The connector was replaced, the EDG was then run to verify speed control and returned to service. NMPC determined that the connector apparently broke due to vibration of the wiring conduit and wrote a DER for engineering to evaluate the mounting of the conduit. Since the Division II EDG configuration is the same as Division I, the evaluation will include the Division II EDG conduit mounting.

4.2.3 Division II Emergency Diesel Generator High Vibration Trip

The operations and I&C departments and the system engineer did an excellent job troubleshooting and repairing a condition that caused a non-emergency trip following a post-maintenance test of the Division II EDG. On November 13 the EDG tripped, during its 5 minute unloaded cooldown run, on an annunciated high vibration condition.

Troubleshooting revealed that a true high vibration condition did not cause the trip, since the vibration trip unit was not in a tripped condition (the unit must be manually reset if it does trip). This trip is pneumatically actuated, with the vibration trip unit bleeding air from its associated pneumatic lines, lowering pressure enough to actuate a pressure switch that initiates an engine trip (unless an emergency signal is present). A check valve upstream of the vibration trip unit will normally hold sufficient pressure in the trip unit pneumatic lines to prevent an engine trip; however, this time, it appears that the check valve leaked enough air to activate the vibration trip unit pressure switch.

I&C technicians removed, inspected, cleaned, and conducted a satisfactory air drop test on the vibration trip unit pneumatic lines. Subsequent operation and cooldown of the diesel was successful.

4.2.4 High Pressure Core Spray Valve Breaker Assembly Inspection

The inspector observed portions of the periodic preventive maintenance and testing on the high pressure core spray (HPCS) suppression pool test bypass valve, 2CSH*MOV111, breaker assembly at the motor control center located in the Division III safety-related switchgear room. The activity was properly performed per electrical preventive maintenance procedure N2-EPM-GEN-V520. Activities specifically observed included: clean, inspect, and test the valve open and close relays, breaker overload contacts, control power transformer, breaker auxiliary contacts, breaker, and cubicle; and installation of the breaker assembly into the motor control center. Proper primary containment integrity was maintained while 2CSH*MOV111, a primary containment isolation valve, was inoperable. The electricians were experienced with the procedure, knowledgeable of the breaker assembly operation, and used proper electrical maintenance techniques. Electrical maintenance supervisory involvement was good. Based on the above observations the inspector concluded that the breaker assembly was in satisfactory condition.

5.0 SURVEILLANCE (61726)

The inspectors reviewed safety-related surveillance activities by observation of testing in progress, interviews, and review of records and verified that: required administrative approval was obtained, procedural precautions and limitations were observed, review of test data was accurate and timely, surveillances conformed to TS, calibrated test equipment was used, radiological controls were observed, and required surveillance frequencies were met.

5.1 Observation of Surveillance Activities - Unit 1

5.1.1 Average Power Range Monitor (APRM) Weekly Instrument Channel Test

The inspector observed the weekly channel functional test on APRM 12 required by TS and noted the following: 1) communications and coordination between the I&C technicians and the control room operators were satisfactory; 2) the I&C technicians had an excellent working knowledge of the procedure; 3) all required log entries were made and proper authorization to perform the procedure was obtained; and 4) the surveillance was conducted properly and resulted in a determination that the instrument was functioning properly.

5.1.2 Feedwater High Pressure Coolant Injection Testing

Operations personnel satisfactorily performed the quarterly feedwater HPCI pump and check valve operability test following procedure N1-ST-Q3, which satisfied the periodic pump and valve operability test required by the TS. The test involved a reactor power reduction to 1800 MW_{th} in order to test with two condensate pumps in operation. It demonstrated that each HPCI pump provided flow above the minimum specified at the pump differential pressure conditions delineated by specification MDC-11, "Pump Curves and Acceptance Criteria." The test also verified that each HPCI pump discharge check valve adequately seated to prevent reverse flow through an idle pump and it obtained vibration measurements from each pump and motor as part of the plant's equipment performance trending program.

The inspector accompanied the system engineer during the test of HPCI train 11 and observed technicians recording flow and differential pressure data. The inspector independently verified that the test data taken was as recorded and then confirmed that the data met the acceptance criteria specified by the procedure. The calculations required by the procedure using recorded test data were also verified to be correct and met specified acceptance criteria. All measuring and test equipment (M&TE) installed for this test was verified to have an appropriate range for the test and was in its current calibration period. The inspector determined that this test adequately demonstrated the operability of HPCI pump 11. The test was properly performed, and was reviewed and accepted by operations management.

The test of HPCI train 11 was also used to provide post-maintenance test acceptability of a repair that was made on a pinhole leak in the 2" recirculation line from the pump to the main condenser. The inspector reviewed the inspection document for this repair and confirmed that the acceptance criteria were satisfied.

After the test of train 11, the inspector reviewed the official test results conducted the prior week for train 12 and verified that the recorded data was acceptable for pump and check valve operability.

5.1.3 Reactor Building Emergency Ventilation Testing

Operators satisfactorily performed the monthly secondary containment and reactor building emergency ventilation system operability test required by TS, over a period of several days, according to surveillance test procedure N1-ST-M8. One ventilation train was removed from service for testing, while the other was kept in a standby condition.

The test involved running each emergency fan for a minimum of ten hours, with the in-line heaters on, while flow and d/p data was obtained to verify proper performance of the charcoal and HEPA filters. The ability of the system to maintain a minimum -0.25 inches of water differential pressure between the reactor building and the outside atmosphere was also confirmed by this test. The inspector observed the system operating indications on the

control room instruments used by operators for the test. Minor inconsistencies in the recorded data were noted by the inspector, but were promptly corrected by operations personnel performing the test. The final recorded data used for system operability were reviewed by the inspector and were properly reviewed by site operations and technical support personnel.

5.2 Observation of Surveillance Activities - Unit 2

5.2.1 Standby Liquid Control System Surveillance Testing

The inspector found that the operability and inservice testing (IST) procedure for the standby liquid control system (SLC), adequately met the requirements of the TS, the updated final safety analysis report (UFSAR), and Section XI of the ASME Code. During testing communications between the personnel were excellent. However, the inspector identified that a pump suction test equipment gauge, needed for IST data, did not meet the procedure requirements. Further, problems were observed with the understanding of I&C technicians using ultrasonic flow meters and vibration instrumentation.

While observing the test, the inspector found that the M&TE pump suction pressure gauge had a range of 0-200 inches of water; while the procedure required the installation of a gauge with a range of 0-100 inches of water. Once this was identified to testing personnel the test was secured and declared invalid. Review of the test procedure showed that 0-100 inch water gauge was specified in the test equipment list, in the test equipment calibration list, and at the installation verification step. Further, the procedure required that if any test equipment was to be used that was different from that specified in the procedure the IST department needed to be contacted and the procedure changed.

The technical significance of using the wrong pump suction pressure gauge range was low since the gauge was digital and, therefore, should have been sufficiently accurate and readable through most of its range; however, the inspector was concerned that licensee personnel failed to follow their procedures and then subsequently failed to note the error themselves. Additionally, as noted in LER 91-03, NMPC personnel have used improper gage ranges during IST on several occasions in the past; however, the changes to the surveillance test procedure initiated as a result of these past problems were very evident, and should have been sufficient to prevent recurrence. Thus, the failure by NMPC personnel to follow the surveillance test procedure was seen as violation of TS 6.8.1 (vice ineffective corrective actions), which requires that written procedures be implemented for surveillance testing (50-410/92-29-01).

Following the identification of the installation of the wrong gauge, a 0-100 inch of water gauge was installed and the test reperformed. NMPC initiated a DER to resolve the gauge installation issue.

During both performances of this test the inspector noted that the flow indication given by the ultrasonic flow device increased as the test was performed, without a change in the system flow characteristic. NMPC determined that the most probable cause was a drift in the instrument's zero point, due to high background sonic energy in the pipe where the flow was being measured or due to an increase in the temperature of the fluid as it was circulated to the test tank. Following the second performance, the flow rate was in the high alert range. However, once the pump was stopped (i.e., system flow was actually zero) the ultrasonic instrument indicated some flow. NMPC initiated a DER to analyze the zero reference drift problem.

The inspector asked the I&C technicians involved in the test about the effects on the vibration instrument frequency response when using the nine inch extension on the probe. The technicians replied that the frequency response was not changed and, thus, the probe could be used when necessary to get to out-of-the-way locations. This indicated a lack of understanding of the vibration test equipment since the use of the probe significantly effects the frequency response. Additionally, as indicated in LER 92-04, NMPC previously failed to meet TS requirements because of improper use and understanding of the nine inch probe extension. If the nine inch probe extension is used to obtain ASME Code required data on the SLC pumps, the frequency response of the vibration instrument will not meet the requirements. The inspector did note that if the surveillance procedure was followed correctly, the nine inch probe extension would not be used for gathering ASME Code data and that it had not been used for this purpose during this test.

NMPC IST supervision were aware of the I&C technicians' lack of knowledge on the use of ultrasonic flow and vibration test equipment. They were working to reduce the number of personnel who operate this equipment, and to increase the training for this smaller group. The inspector had no additional questions or concerns.

6.0 ENGINEERING AND TECHNICAL SUPPORT (71707, 37700)

6.1 Unit 1

6.1.1 Preliminary Review of Primary Containment/Reactor Coolant System Isolation Valve Administrative Deficiencies

As discussed in section 1.2.1 above, a 10 CFR 2.206 petition was received which dealt in part with administrative deficiencies on primary containment and reactor coolant system isolation valves. Attachment 5 to the petition provided a list of 84 valves, and 17 associated notes describing these deficiencies. To ascertain if there were any current operability concerns with the listed valves the inspector reviewed: IST program plan issued on November 2, 1992, the UFSAR, the current TS, a proposed TS amendment dated February 7, 1992, and the numerous surveillance tests used to demonstrate operability of primary containment and reactor coolant system isolation valves.

Preliminarily, the inspector found that of these 84 valves, 76 were currently in the IST program, with appropriate testing listed including; exercise, stroke timing, and leakage rate testing. Four valves were associated with the non-safety related HPCI mode of the feedwater system and therefore, were not in the IST plan. Two other valves were not in the IST plan since blank flanges had been installed upstream of the valves. The final two valves were not included in the IST plan since the valves did not need 10 CFR 50, Appendix J testing due to a water seal. With respect to differences between the TS tables and the UFSAR tables for these valves, the inspector found that the proposed TS amendment addressed the concerns for valves currently considered by NMPC to be isolation valves. The proposed TS amendment also clarifies the leakage rate testing requirements for valves which currently are exempted from the requirement of 10 CFR 50, Appendix J. Review of surveillance testing showed that applicable testing criteria for stroke timing were being implemented. If a valve was currently not in the TS tables it was being tested as appropriate with the IST plan, with stroke times that were more conservative than those specified in the proposed TS amendment. The inspector also verified that valves which receive automatic closure signals on a loss of coolant accident were properly functionally tested during the performance of the refueling cycle loss of coolant/loss of offsite power function test.

This preliminary review did not identify any condition that would indicate that the identified valves were not being tested to ensure their operability. NMPC stated that this amendment corrects all the noted problems and that once it is issued the UFSAR will be updated. However, the proposed TS amendment has not been issued and is still under review by the NRR staff.

6.2 Unit 2

6.2.1 Temporary Modification of the Unit 2 B-Loop Recirculation Flow Controller

During power ascension, following the scram on November 4, the plant experienced significant flow oscillations on the B recirculation loop, caused by problems with the valve stem velocity sensor for the B flow control valve. NMPC implemented a temporary modification to the recirculation flow controller rather than enter the drywell and repair the sensor. The modification, recommended by GE, was installed and tested with a GE technical representative present at the site. The most significant part of the modification consisted of removing the velocity sensor input from the control circuit and replacing it with a signal of constant value.

The inspector reviewed the engineering design change package and the associated 10 CFR 50.59 safety evaluation, and observed portions of the modification testing. The inspector found that the modification was technically sound and would allow proper operation of the recirculation flow control valve. Further, the safety evaluation adequately demonstrated that an unreviewed safety question did not exist as a result of the modification and that TS requirements were not affected.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707, 92700)

7.1 Review of Licensee Event Reports - Unit 1

LER 91-07, dated July 23, 1991, discussed a reactor building emergency ventilation system isolation due to a damaged cable in a radiation monitor trip unit. NMPC initially committed to replace the damaged cable during the next refuel outage; however, subsequent engineering evaluation determined that a permanent repair to the existing cable would be satisfactory. The inspector agreed that the repair would be satisfactory following discussions with NMPC personnel. A supplement to the LER will not be issued.

7.2 Safety Review and Audit Board Meetings

The inspector observed portions of the Safety Review and Audit Board (SRAB) meeting on December 2, 1992, and reviewed the October 7-8, 1992, SRAB meeting minutes. The SRAB, composed of senior managers, engineers, and consultants, technically competent in various fields of nuclear energy, functions to provide an independent review and audit of designated plant activities per TS 6.5.3. Proper committee composition was present and presentations by various members and subcommittees were clear and well prepared. In-depth discussions were held on various safety-related matters including: entry into limiting conditions for operation for planned maintenance while operating, the frequency of loss of offsite power events at Unit 2, and engineering implementation of the software QA program. The inspector concluded that both SRAB meetings satisfied the objectives of TS 6.5.3.

7.3 (Open) Unresolved Item 50-220/92-24-04 and 50-410/92-28-04: Adequacy of Corrective Actions

As part of the effort to assess the adequacy of recent corrective actions, the inspectors reviewed all of the 1992 LERs for both units. The most common similarity between the events was the failure of NMPC personnel to assess adequately the plant impact associated with various conditions and actions. During 1992, nine reportable events were caused, at least in part, by improper assessment of the potential affects of operations and maintenance activities. A brief summary of each event is listed below. Any violations of regulatory requirements have been addressed in previous inspection reports.

Unit 1

• January 10 and 22, 1992 (LER 92-01) - Operators failed to take actions required by the Unit 1 TS when portions of the turbine stop valve closure scram and the generator load reject scram were bypassed at greater than 45% power. The bypass conditions occurred because of an equipment malfunction together with an improper valve lineup. The operators were aware of the problem because of an annunciator indicating that the main turbine first stage pressure was low.

The most significant cause of the operator's failure to follow the TS was that they apparently did not fully understand the implications of the turbine first stage pressure instrument sensing a low pressure condition. Further, the abnormal alarm was not logged by the operating crew and a DER was not written.

- February 21, 1992 (LER 92-05) - The plant was isolated from its ultimate heat sink (Lake Ontario) for approximately five minutes. This was a result of closing the screenhouse forebay, with the plant in a reverse flow condition, and the subsequent inability to reopen Gate D immediately. Gate D was closed to test its control circuit following modification.

A contributing cause of this event was that operators and maintenance supervision failed to assess adequately the potential impact of closing Gate D on the plant.

- September 4-5, 1992 (LER 92-10) - Several instances occurred where the minimum number of operable reactor trip system channels was less than required. This resulted from bypassing two intermediate range neutron monitors because of anticipated "spiking," then subsequently placing average power range neutron monitors in bypass for various operational and maintenance reasons.

  The most significant cause of this event was that the control room operators did not correctly assess the effect of concurrently placing various neutron monitors in a bypass condition.

Unit 2

- January 10, 1992 (LER 92-03) - An unexpected secondary containment isolation signal was received when workers de-energized a reactor building ventilation system radiation monitor (the above refuel floor monitor). The system responded correctly to the loss of power.

The cause of this event was a failure to perform an adequate job/plant impact assessment prior to commencing work on the radiation monitor.

- March 23, 1992 (LER 92-06) - The plant lost both 115 kV offsite power sources, lines 5 and 6. Line 5 was lost when technicians accidentally actuated an over-current relay during maintenance. Line 6 was subsequently lost when operators attempted to cross-tie it to the line 5 loads. Line 6 was isolated from the plant, by design, because of interlocks (associated with the over-current relay trip) that were affected when the cross-tie was attempted.

The cause of this event was a failure to perform an adequate job/plant impact assessment prior to commencing work on the over-current relay. Additionally, operators compounded the event by improperly assessing the impact of the relay trip on the ability of line 6 to supply line 5 loads.

- July 28, 1992 (LER 92-18) - The plant lost 115 kV offsite power line 6 due to failure of its associated offsite supply breaker; however, NMPC personnel were aware that the breaker was experiencing problems more than thirteen hours before the trip; but they improperly assessed that the malfunction would not cause the breaker to trip.

  A significant contributing cause of this event was a failure to perform an adequate plant impact assessment of the breaker malfunction.

- August 22, 1992 (LER 92-17) - The reactor scrammed on low reactor vessel water level during an attempt by the control room operators to switch feed pumps.

  The cause of this event was improper operation of the feedwater and condensate systems. The operators did not understand the consequences of some of their manipulations of these systems.

- September 16, 1992 (LER 92-19) - The plant experienced an automatic isolation of the reactor water cleanup system (an engineered safety feature) due to a high temperature condition in the reactor water cleanup system pump room. The high temperature condition was caused by an improper ventilation system configuration. The improper configuration was established during maintenance on the emergency recirculation unit coolers.

  The cause of this event was a failure to perform an adequate plant impact assessment of the maintenance on the emergency recirculation unit coolers.

- September 25, 1992 (LER 92-20) - The plant lost 115 kV offsite supply line 5 when a crane boom, being used to place concrete, came close to the line, and the resulting arc through the crane to the ground caused the line to trip.

  A possible contributing cause of this event was a failure to perform a plant impact assessment of the work. If the work had been assessed for plant impact, and had been coordinated with the control room, the incident might have been prevented.

The corrective actions for each event listed above have generally been good when considering the individual event and possibly one or two past events. The corrective actions tended to focus on fixing or creating procedures, letting other personnel know about the event (via a Lessons Learned Transmittal), and conducting some specific event related

training. The corrective actions have not, however, focused on the broad scope of failures to assess adequately the impact of various operations and maintenance activities. NMPC was conducting their own analysis of past LERs for the adequacy of corrective actions. This unresolved item remains open pending further inspector review.

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.