U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/96-13 50-410/96-13
License Nos.:	DPR-63 NPF-69
Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	October 20 - November 30, 1996
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/96-13 & 50-410/96-13
October 20 - November 30, 1996

This integrated inspection report includes reviews of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection. In addition, it includes the results of an in-office review by a regional inspector in the area of emergency preparedness.

PLANT OPERATIONS

During this inspection period, Unit 2 completed its fifth refueling outage (RFO5), and returned to full power operation on November 6. On November 21, while attempting to parallel one of the Unit 2 emergency diesel generators (EDGs) with off-site power, the operator inadvertently closed the output breaker about 120 degrees out-of-phase from the off-site power source. Closing the breaker out-of-phase had the potential to render the EDG inoperable, and cause the associated emergency equipment to be unavailable. Niagara Mohawk Power Corporation (NMPC) inspected the EDG and associated equipment, and identified no damage.

The inspectors conducted a walkdown of the Unit 1 core spray (CS) system. The CS system was properly aligned, and no significant equipment deficiencies were identified. The overall material condition of the pumps, valves, piping, and supports was good. General housekeeping was acceptable.

On November 5, 1996, Unit 1 experienced a turbine trip and reactor scram, due to one of the flexible conductor links in the generator exciter wearing through and contacting the structural steel exciter casing. Reactor vessel water level rose above the narrow range (NR) level instrument indication and eventually entered the emergency condenser steam lines and the main steam lines. The operators had difficulty controlling reactor vessel level due to an inadequate scram procedure and a feedwater system flow control valve (FCV) that leaked excessively. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-19 "Safety Implication of Control Systems in LWR [Light Water Reactor] Nuclear Power Plants," notes that a reactor vessel overfill can affect the overall safety of the plant; and could lead to a steam line break, should the main steam lines become flooded.

During the subsequent NMPC investigation, the licensee identified that a Deviation/Event Report (DER) was written in 1992 documenting that the wide range level instrument read lower than expected during power operations; however, the condition was not properly dispositioned in a timely manner, and the operations staff was not made aware of this discrepancy. This is an apparent violation of 10 Code of Federal Regulations (CFR) 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC Quality Assurance Topical Report (QATR), which require that conditions adverse to quality are reported to the appropriate level of management for review, and corrected in a timely manner.

Executive Summary (cont.)

The reactor water level increased rapidly during the November 5 scram due to excessive leakage past the #12 feedwater pump FCV. In July 1996, during a normal reactor shutdown, level also increased quickly. Through discussions with Unit 1 staff, the inspectors ascertained that one of the reasons for the rapid level increase in July was that the FCVs leaked. The licensee did not document this on a deviation/event report or work order, nor evaluate the extent of the leakage. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, which require that conditions adverse to quality be documented and the extent of the problem be evaluated.

The Unit 1 scram procedure does not provide sufficient direction to control water level and prevent a reactor vessel overfill condition. GL 89-19 and a Unit 2 overfill event (January 1988) should have been adequate for Unit 1 to develop an appropriate procedure to prevent the ingress of water into the main steam lines during the reactor scram of November 5, 1996. A similar event occurred at Unit 1 during a normal reactor shutdown in July 1996. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, which require that conditions adverse to quality are documented and that corrective actions are implemented in a timely manner.

MAINTENANCE

The inspectors observed the Unit 1 control room operators perform a surveillance test for the EDGs and vital power boards. The operations were performed carefully and without difficulty, communications between the operators in the turbine building and the control room were adequate. The operators appeared to understand the scope of the surveillance test and accomplished the evolution without incident.

During a review of the CS system, the inspectors identified that eight pressure control valves were found out of tolerance during the bi-annual calibration, and one of the valves had a history of being found out of tolerance every time the calibration was performed. The inspectors noted that there was not a process to trend the out-of-tolerance as-found conditions; this could result in system reliability being questioned and surveillance periodicity to be in doubt.

ENGINEERING

NMPC identified several welds at both units that had not been inspected at the frequency required by the inservice inspection (ISI) program. The welds required augmented inspections for intergranular stress corrosion cracking, but were not incorporated into the ISI program during the evaluation of NRC GL 88-01. This included five welds in the Unit 1 core spray system, and eight welds in the reactor recirculation system. Also, sixteen welds were identified in the Unit 2 reactor water cleanup system that had not been inspected at the required frequency. NMPC determined the preliminary root cause was that commitments to change the program were not properly incorporated. The failure to complete the required inspections was a violation of the Unit 1 and Unit 2 Technical Specifications. **(VIO 96-13-03)**

Executive Summary (cont.)

NMPC notified the NRC that Unit 1 may have operated outside its design basis from March 1982 until February 1995, due to the potential for a hot short condition to cause the motor operator for two shutdown cooling system containment isolation valves to malfunction and prevent the valves from being opened within 72 hours to achieve a cold shutdown condition.

During RFO5, NMPC identified a significant amount of foreign material in the Unit 2 suppression pool downcomers, which had the potential to adversely impact the operability of the emergency core cooling system (ECCS) due to clogging of the ECCS pump suction strainers. In addition, the licensee found that seven of the eight downcomers located in the pedestal support under the reactor vessel had a hard plastic cover over the top of the downcomer. The suppression pool was cleaned in RFO4 and a significant amount of foreign material was removed. At that time, NMPC documented that most of the debris must have entered via the downcomers, but did not examine the downcomers. As a result, the suppression pool was not adequately cleaned during RFO4, and a significant amount of debris was left in the downcomers from June 1995 until October 1996. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, which require measures to ensure conditions adverse to quality are promptly identified and corrected.

The failure to identify and remove the caps on the downcomers in the pedestal support during all drywell closeout inspections from initial startup until October 1996, is an apparent violation of procedure N2-OP-101A, "Plant Start-Up;" in that, a detailed inspection of the drywell was not performed to ensure that all loose material was removed prior to startup.

NMPC was informed by the Department of Defense that some pressure relief valves sold as being manufactured by Anderson Greenwood may be counterfeit. Upon identification of the concern, NMPC segregated all Anderson Greenwood valves in stock, and reviewed procurement records to determine the location of the valves installed in the plant. One valve was currently installed in a non-safety application at Unit 2. NMPC's actions to address the potentially counterfeit Anderson Greenwood valves were appropriate.

PLANT SUPPORT

During a tour of the protected area perimeter, the inspectors found the fence and perimeter detection system intact; in addition, the central and secondary alarm stations were appropriately staffed.

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SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) started the inspection period at full power. On November 5, Unit 1 experienced a turbine trip and reactor scram due to a valid generator exciter ground relay signal. NMPC restarted the unit on November 12, after completion of repairs. Full power operation was achieved on November 14 and continued to the end of the report period.

Unit 2

Nine Mile Point Unit 2 (Unit 2) started the inspection period in the middle of the fifth refueling outage (RFO5). The reactor was started up on October 31, and the unit achieved full power on November 6. The unit maintained essentially full power for the remainder of the inspection period.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC conducted inspection activities during normal, backshift, and deep backshift hours. In addition to the inspection activities completed by the resident inspectors, a regional inspector conducted an in-office review in the area of emergency preparedness. The results are contained in the applicable sections of this report.

Also, two other NRC inspections were completed during this period. The inspection reports will be issued separately:

- Generic Letter 89-10 Closure of Motor Operated Valve Issues for Unit 2: Inspection Report 50-410/96-15

- Engineering Inspection for Unit 2: Inspection Report 50-410/95-16

Updated Final Safety Analysis Report (UFSAR) Reviews

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with UFSAR commitments. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

I. OPERATIONS

O1 Conduct of Operations (71707) [1]

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was properly focused on safety; specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 2 Reactor Startup Following the Fifth Refueling Outage (RFO5)

On October 30, 1996, the inspectors observed the special evolution briefing for the operating crew prior to the reactor startup following RFO5. The briefing was adequate and included all of the requirements contained in generation administrative procedure GAP-SAT-03, "Control of Special Evolutions," Revision 3. The inspectors observed portions of the reactor startup on October 31, 1996. The startup was completed, without incident, in accordance with procedure N2-OP-101A, "Plant Start-up," Revision 11. The communications by the control room operators were acceptable, and shift management maintained good command and control of the evolution.

O1.3 Unit 2 Emergency Diesel Generator Paralleled Out-of-Phase

a. Inspection Scope

On November 21, 1996, while attempting to parallel the Division 2 emergency diesel generator (EDG) with off-site power during a Unit 2 surveillance test, an operator inadvertently closed the EDG output breaker approximately 120 degrees out-of-phase from the off-site power source.

Subsequently, the inspectors reviewed the procedure used during the evolution, visually inspected the EDG, discussed with the system engineer the bases for determining the EDG operable, and observed the completion of the surveillance test.

b. Observations and Findings

On November 21, 1996, while Unit 2 was at 100% power, the Division 2 EDG was successfully started and warmed for the required fast loading portion of surveillance procedure N2-OSP-EGS-M@001, "Diesel Generator and Diesel Air Start Operability Test - Division I and II," Revision 01. After checking voltage and frequency, the reactor operator (RO) shut the EDG output breaker (2ENS*SWG101-1) about 120

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

degrees out-of-phase from the off-site power source supplying the emergency bus. The output breaker stayed shut. Shortly following the event, the station shift supervisor (SSS) directed the RO to unload and shutdown the EDG in order to determine if any damage had occurred to either the EDG or associated equipment. The surveillance was aborted and the EDG was declared inoperable.

The system engineer identified no abnormalities during a visual inspection of the diesel generator foundation bolts, the generator stator, and the EDG output breaker. In addition, the system engineering staff had no concerns relative to the impact of the voltage transient on the generator. NMPC also contacted the diesel and generator vendors, and confirmed that the event should have no adverse effect on the equipment and that visual inspections were appropriate. The EDG was declared operable after being satisfactorily retested, using the normal loading portion of surveillance procedure N2-OSP-EGS-M@001.

The inspectors performed an independent visual inspection of the diesel generator foundation bolts and found no abnormalities. Additionally, the inspectors discussed the event with the system engineer and considered the NMPC decision to declare the EDG operable to be appropriate.

The inspectors reviewed the portion of surveillance procedure N2-OSP-EGS-M@001 used during the event, and determined that the procedure contained sufficient detail for completion of the evolution. By the close of this inspection period, NMPC had not completed their root cause analysis for the improper paralleling operation.

Procedure N2-OSP-EGS-M@001, Step 8.3.27, requires the breaker to be closed when the synchroscope reaches the 11 o'clock position. The failure to close 2ENS*SWG101-1 at the 11 o'clock position on November 21, 1996, was a violation of Technical Specification (TS) 6.8.1. TS 6.8.1 requires, in part, that written procedures be established and implemented. This licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VIII.B.1. of the NRC Enforcement Policy.

The inspectors observed the paralleling and fast loading portion of the surveillance test on November 26, 1996. The evolution was completed in accordance with surveillance procedure N2-OSP-EGS-M@001. The inspectors noted no discrepancies.

c. <u>Conclusion</u>

The out of phase paralleling of the Division 2 EDG with the off-site electrical source on November 21, 1996, had the potential to render the EDG inoperable, and cause the associated emergency equipment to be unavailable. The immediate corrective actions taken by NMPC to return the EDG to operable were adequate; NMPC initiated a detailed root cause analysis to determine additional actions to preclude recurrence.

O2 Operational Status of Facilities and Equipment

O2.1 Cold Weather Preparations (71714)

a. Inspection Scope

The inspectors reviewed NMPC's program for protection of safety-related systems and equipment against extreme cold weather. The inspectors held discussions with operations, work control, and fire protection management and staff.

b. Observations and Findings

At Unit 1, plant systems possibly affected by cold weather included circulating water and building ventilation. The systems operating procedures contained guidance for the abnormal condition of low ambient temperatures. Specifically, the circulating water system operating procedure, N1-OP-19, Rev. 21, Section H, discussed the indications of, and operator actions for, the formation of frazil ice at the intake structure. When lake temperature remains low, operators realign the circulating water intake gates for de-icing. Reactor and turbine building ventilation system heaters would automatically energized and deenergized based upon system temperature. These heaters are located within the ventilation ducting and would not prevent snow and ice buildup on the intake louvers; however, control room annunciators would alarm for high system differential pressure if blockage occurred.

The inspectors verified the completion of Unit 2 maintenance activities for the cold weather conditions. The activities were in accordance with procedures N2-PM-A001, "Annual Draining and Refilling of ACUs [air conditioning units] and Cooling Coils," Revision 00, and N2-PM-A004, "Annual Removal and Installment of HVR [heating, ventilation, and refrigeration] Supply Prefilters," Revision 00. Also, the operability of the service water heater system is verified during checks each shift (N2-OSP-LOG-S001) and periodically during the performance of TS 4.7.1.1.2 required surveillance. The inspectors considered the cold weather preparations at Unit 2, and the controls in place to ensure the annual completion of these preparations, to be appropriate.

With the onset of cold weather, fire protection personnel conduct routine rounds with an increased emphasis toward the effects of cold weather. Specifically, personnel ensured that buildings were adequately heated and not open to the outside. Fire protection equipment located outside of buildings was designed for cold weather; for example, fire hydrants and standpipes were self-draining, and the piping and valves were installed below the frost line.

c. Conclusions

Although the method and planning for cold weather preparations differs between the units, the inspectors did not identify any systems or components that were not adequately protected against severe weather. NMPC did not have a formal program specific to cold weather preparation, but protection was provided through

Maintenance and Operations procedures. Additionally, protection against the effects of extreme cold weather was inherent in the design of both units.

O2.2 Unit 1 Core Spray System ESF Walkdown (71707)

System Description

The core spray (CS) system, in conjunction with the automatic depressurization system (ADS), is the standby emergency core cooling system for decay heat removal in the event of a loss of coolant accident (LOCA). The CS system is a low pressure system. As necessary, the ADS reduces system pressure to within the CS system parameters, as in the event of a small break LOCA. ADS is not required for large break LOCAs. The CS system is capable of providing the required core cooling for break sizes up to the largest possible design basis accident consisting of a double-ended recirculation pipe rupture. The CS pumps take suction from the torus (suppression chamber), and discharge into the reactor vessel above the fuel assemblies. The CS system consists of two loops (11 and 12); each loop contains two 100%-capacity pumps, associated injection valves, and independent power sources. The CS system automatically initiates on either a low-low reactor water level or high drywell pressure signal.

a. Inspection Scope

The inspectors conducted a walkdown of the Unit 1 CS system to assess material condition and evaluate the ability of the system to perform its intended function. The walkdown included all accessible areas of Loop 12, from the torus containment room to the drywell, and portions of Loop 11. The inspectors reviewed completed surveillance tests for the last two quarters and the operating procedure, N1-OP-2, "Core Spray System," Revision 26. The inspectors discussed the results with the SSS, maintenance supervision, the CS system engineer, and the inservice testing (IST) supervisor.

b. Observations and Findings

The inspectors did not identify any discrepancies between actual and expected normal system lineup. All valves were in the required position, evidenced by either local examination and/or valve position indication in the control room. The CS pumps and CS topping pumps appeared to have normal packing leakage, as evidenced from past surveillance tests. No current system leakage was identified. Most system valves, piping, and supports were in good condition. In general, housekeeping was acceptable. Several maintenance related deficiencies were identified and are described in Section M2.1 of this report.

Numerous system components lacked nameplates or identification. The inspectors determined, by a review of the system operating and emergency procedures, that none of the components required operator manipulation during abnormal or emergency conditions. Most unlabelled components either did not have an operator (e.g., check valve, ball joint, or relief valve) or were infrequently operated. The

system engineer informed the inspectors that the intent was for all components to be properly identified and that there was an outstanding work order (WO) addressing the issue.

c. Conclusions

The CS system was properly aligned, and no significant equipment deficiencies were identified. The overall material condition of the pumps, valves, piping, and supports was good. General housekeeping was acceptable.

O2.3 Unit 1 Reactor Vessel Overfill Event

a. Inspection Scope

On November 5, 1996, Unit 1 experienced a main generator trip, which resulted in a turbine trip and reactor scram. The generator trip was due to a valid ground fault relay actuating signal; one of the flexible conductor links in the generator exciter had worn through and contacted the structural steel exciter casing. Complications following the trip were related to high reactor vessel water level. Level rose above the narrow range (NR) level indication and eventually entered the main steam lines (MSLs).

The inspectors interviewed NMPC management and the Unit 1 operating crew involved with the transient. In addition, the inspectors reviewed the operators' logs, historical graphs and trends and computer printouts, attended meetings and Station Operations Review Committee (SORC) meetings, and researched industry operating experience.

b. Observations and Findings

Background

On November 5, 1996, Unit 1 experienced a reactor scram due to a turbine trip. All control rods inserted, vital electrical distribution panels automatically transferred to off-site power, and the high pressure coolant injection system (HPCI) initiated, as expected, on the turbine trip signal. Initial event response by the operators was appropriate and in accordance with special operating procedure N1-SOP-1, "Reactor Scram."

Motor-driven feedwater pump (FWP) #11 and shaft-driven FWP #13 were running prior to the scram, and motor-driven FWP #12 started on receipt of the HPCI initiation signal. The #11 and #12 FWPs shifted to the HPCI mode of operation. The #13 shaft-driven pump continued to inject to the vessel for several minutes as the main turbine coasted down. All three FWP flow control valves (FCVs) went full open due to the low reactor vessel water level after the scram. The running HPCI pump (#11) tripped on low suction pressure shortly after the second HPCI pump started. This was not an unusual condition and had been previously analyzed by

NMPC as an acceptable system response due to the #13 shaft-driven pump injecting the majority of the water immediately after the scram.

Procedure N1-SOP-1 directed the operators to maintain reactor water level between 53 and 95 inches; but did not specifically address how to avoid a reactor overfill condition. As reactor water level increased, the following automatic actions occurred. At 65 inches, the #11 FCV shut to maintain programmed level; at 72 inches, the #12 FCV shut. At 95 inches, a reactor high water level signal was sent to the HPCI pumps. The overfill protection logic for Unit 1 is a coincident circuit. If reactor level remains above 95 inches for 10 seconds, and the associated FCV indicates shut, the pump continues to run at minimum flow; if the valve is not shut, then the associated HPCI pump trips. Also at 95 inches, the #13 pump declutches from the turbine shaft. During the event when reactor water level reached 95 inches, the #11 FWP had already tripped on low suction pressure, the #13 FWP declutched as designed, and the #12 FWP continued to run with the associated FCV indicating shut. However, the FCV for #12 FWP was known to leak, but at the time of the scram, the extent of the leakage was unknown.

Reactor water level continued to increase above the top of the NR level indication (100 inches). The emergency condenser (EC) steam lines tap off the vessel at 97 inches and the main steam lines tap off at 140 inches (11.7 feet on the wide range (WR) level instrument). Operators were monitoring the WR instrument, and the Chief Shift Operator (CSO) directed another operator to close the main steam isolation valves (MSIVs) if WR level reached 11.0 feet. Level stabilized at about 10.5 feet on the control room WR meter. Subsequently, the inspectors determined the water had entered the MSLs.

NRC Generic Letter 89-19 "Safety Implication of Control Systems in LWR [Light Water Reactor] Nuclear Power Plants," notes that a reactor vessel overfill can affect the overall safety of the plant. The more severe scenarios could potentially lead to a steam line break, due to increased dead weight and seismic loading, should the steam lines become flooded. In addition, water hammer and two-phase flow could cause dynamic loading and/or secondary valves sticking open, resulting in MSIVs or turbine stop valves becoming inoperable. The overfill protection design should ensure that the main feedwater pumps will trip on a reactor high water level signal.

<u>Reactor Water Level Indication Problems</u>

The inspectors reviewed what instrumentation was available and being used by the operators to monitor reactor water level. Per discussions with the SSS, operations management, operators, and instrument and control (I&C) technicians, the inspectors determined:

- The NR level instrument indicates 0 to 100 inches and is calibrated for hot ambient conditions. Normal operating level is 65 to 83 inches indicated on the NR instrument. The NR level instrument meter was pegged high.

- A digital display can display either of the NR instruments. The digital display will provide indication above 100 inches, but is only calibrated to 100 inches. The upper tap for the NR level detector is at 114 inches. Operators are trained to use the digital for an indication of water level trend only. The highest digital reading noted by the operators was 123 inches.

- The WR level instrument reads from -1 foot to 27.5 feet. The instrument is cold calibrated, and uses a density compensation correction factor to approximate hot operating conditions. Normal operating level on the NR instrument correlates to about 5.5 to 7 feet on the WR instrument. Operators stated that level never exceeded 11.0 feet as indicated on the WR instrument.

- A computer point can be used to indicate the WR level. Operators did not use this indication.

NMPC reactor engineering personnel were able to obtain a graph of reactor water level for the transient, using the computer point of uncorrected WR level discussed above. The maximum level indicated on the graph was 10 feet (about 117 inches) which was consistent with the reports of the operators. The NRC inspectors asked NMPC to determine the appropriate correction factor and provide a graph of compensated level. While doing a manual calculation, NMPC found a computer point which used showed corrected WR level. The corrected computer graph indicated that reactor vessel water level exceeded 12 feet for about 50 minutes; the MSL tap-off is at 11.7 feet. During the licensee's review of the WR indication, NMPC identified an old 1992 deviation/event report (DER 1-92-3353) which noted that the WR meter reads about one foot lower than expected at normal operating conditions; the DER was still open on the day of the scram. The control room operators were not aware of the 1992 DER or the discrepancy between actual and indicated WR level.

The fact that a 1992 DER was written documenting that the WR meter read lower than expected during power operations, that the condition was not properly dispositioned in a timely manner, and that the control room operators were not made aware of this discrepancy, is an apparent violation of 10 Code of Federal Regulations (CFR) 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC Quality Assurance Topical Report (QATR), which requires that conditions adverse to quality are reported to the appropriate level of management for review, and corrected in a timely manner.

Analysis of Water Entering the Emergency Condenser Steam Lines

The control room operators were aware that water entered the steam lines for the emergency condenser (EC). On a walkdown of the system immediately after the scram, they noted a heavy dust layer on the floor in the area of the EC steam lines. NMPC considered this indicative of possible water hammer in the EC steam lines and initiated DER 1-96-2999 to request that engineering perform an operability determination of the EC system.

NMPC engineering noted in the DER disposition that the transient was not water hammer, by definition, but was similar in effect. NMPC engineers, experienced in piping design and system interaction, performed a detailed inspection of the system and determined that the damage was limited to insulation and that there was no damage or deformation which would adversely affect the system operability.

During review of the DER, the inspectors questioned if the operability of the decay heat removal function of the EC system had been considered with respect to water acting as a blockage for the steam lines. Specifically, would there be sufficient driving head for the natural circulation design of the steam cooling. NMPC had not considered this concern during the disposition of the DER, but initiated an evaluation to determine the operability of the EC system during overfill conditions. This is unresolved pending NRC review of the NMPC evaluation. **(URI 50-220/96-13-01)**

Analysis of Water Entering the Main Steam Lines

Due to the WR level instrument inaccuracy described above, water level exceeded the tap-off for the main steam lines. NMPC did not recognize that level reached the main steam lines until the inspectors requested NMPC to perform a correction to the WR computer graph to compensate for the cold calibrated condition. It was then that NMPC learned that water entered the main steam lines for about 50 minutes. DER 1-96-3029 was written to document the evaluation.

A detailed walkdown of the main steam system identified that a structural support rod and a snubber were damaged; DERs 1-96-3034 and 1-96-3049 were written. Two hangers for the service water system, in the vicinity of the snubber, were also damaged. The damage was repaired using approved work orders. In addition, the turbine control and stop valves, and the bypass valves were successfully stroked open and closed to ensure no damage resulted due to the high pressure water impact.

By means of a flow-mass balance, based on feedwater injection and cleanup system rejection rates, NMPC engineering calculated that approximately 300,000 pounds mass of water entered the steam lines. This equates to about 30,000 gallons of water.

Unit 1 also had difficulties controlling reactor vessel water level during a normal plant shutdown in July 1996 (reference NRC Inspection Report 50-220/96-10). Since indicated level on the digital exceeded 120 inches, the inspectors requested NMPC to provide a corrected WR computer printout for that transient. The graph indicated that reactor level peaked at about 11.75 feet, and that water may also have entered the main steam lines for about 3 minutes during that shutdown.

Flow Control Valve Leakage

During review of the computer graphs, NMPC noted that the flow from the #12 FWP was about 300,000 pounds mass per hour (about 600 gallons per minute (gpm) with the FCV indicating closed. The root cause, as identified on the DER (1-

96-3019), was abnormally high leakage past the #12 FCV. Design specification allows leakage of about 20 gpm (½% full flow).

Testing of the valve positioner for #11 FCV revealed that the valve was not fully closed with a minimum signal from the HPCI controller. The #12 FCV was not able to be tested as the valve was being rebuilt, but NMPC believed that #12 FCV valve positioner was probably slightly worse. A contributing factor was the valve limit switches, which allowed the valve to be slightly open and still indicate closed. In addition, NMPC noted the #12 FCV valve seat and disc were eroded, which also contributed to the valve's leakage. Although the overfill protection logic circuit performed as designed (i.e., the FWP trips at 95 inches only if the associated FCV is open), the leaking FCV essentially bypassed the intended function of the logic.

During discussions with the inspectors, licensee staff acknowledged that there was a missed opportunity after the July 96 shutdown to identify the extent of the leakage on the FCVs and facilitate repairs at that time.

The reactor water level increased rapidly due to excessive leakage past the #12 FCV (about 600 gpm). In July 1996, during a normal reactor shutdown, level also increased quickly. The Unit 1 Operations Manager informed the inspectors that, for the July 1996 shutdown, one of the reasons for the rapid increase was that the FCVs leaked. The licensee did not document this on a DER or work order, nor evaluate the extent of the leakage. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, which require that conditions adverse to quality be documented, and that the extent of the problem be evaluated.

Inadequate Scram Procedure

Per NRC GL 89-19, the specific objective of reactor vessel overfill protection is to enhance the safety of the plant by minimizing the potential for water ingress into the steam lines. Emergency procedures should be written such that operators verify that automatic actions occur when expected, and that manual actions are detailed in the event that those automatic actions do not occur.

The inspectors determined that the Unit 1 special operating procedure (SOP) for a reactor scram, N1-SOP-1, was inadequate. The operators are not required to verify that the HPCI pumps stop injecting at 95 inches, nor are the operators directed to take any manual actions to ensure that an overfill condition does not occur. The procedures states:

> Maintain Reactor Pressure Vessel (RPV) Water Level between +53 inches and +95 inches using one or more of the following:
> - Condensate and Feedwater
> - Control Rod Drive
> - Core Spray

The purpose of this procedural step is to maintain the reactor core covered. No where in the reactor scram procedure is the operator directed to trip the HPCI pumps or close the MSIVs.

In January 1988, Unit 2 experienced a vessel overfill event, although the causes were different. The NRC Inspection Report 50-410/88-01, Section 5.3, noted that procedure improvements were needed to address vessel overfill protection strategy. For comparison, the current Unit 2 special operating procedure N2-SOP-101C, "Reactor Scram," is very detailed. For example:

> If RPV level continues to rise and can not be maintained below 187.3 inches, the operators are directed to verify various valves are closed and to trip one feedwater pump. If level continues to rise, the operators are directed to trip the remaining feedwater pump, and to verify that the high pressure core spray and reactor core isolation cooling pumps are not injecting. Finally, if level cannot be maintained below 250 inches, the operators are directed to close the MSIVs.

NMPC improved the Unit 2 scram procedure with sufficient detail to aid the operators during emergency conditions. However, adequate corrective actions were not taken at Unit 1 to improve the scram procedure based on industry experience, including the Unit 2 event.

The Unit 1 scram procedure does not provide the operators with sufficient direction to control RPV water level. NRC Generic Letter 89-19 and a Unit 2 overfill event provided industry experience that should have been adequate for Unit 1 to develop an appropriate procedure to prevent the ingress of water into the main steam lines during the reactor scram of November 5, 1996. A similar event occurred during a normal reactor shutdown in July 1996. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, which requires that conditions adverse to quality are documented and that corrective actions are implemented in a timely manner.

c. <u>Conclusions</u>

Following the Unit 1 turbine trip and reactor scram on November 5, 1996, the unit experienced a reactor vessel overfill event and water entered the main steam lines. This is considered a significant event because of the potential for damaging the main steam line piping and valves. During NMPC's post-scram review, the licensee did not realize that water had entered the main steam lines until questioned by the inspectors. Subsequently, based on a graph of the wide range level instrument indication corrected to compensate for the cold calibrated condition, the licensee determined that approximately 30,000 gallons of water entered the main steam lines. The inspectors also noted the licensee had not considered the possible effect on emergency condenser operability when water entered the EC steam lines and essentially acted as a hinderance to the driving head for the natural circulation design for steam cooling.

The inspectors noted that contributing to the reactor vessel overfill event were: 1) a discrepancy with the wide range level instrumentation at normal operating conditions. The problem was documented on a 1992 DER, but the condition was not dispositioned in a timely manner and the operations staff, which relied upon the instrument during the event, was not aware of the discrepancy; and 2) a leaking feedwater flow control valve. It appears the leaking FCV also contributed to a high water level condition during a normal reactor shutdown in July 1996, but the licensee did not document the problem nor evaluate the extent of the problem. In addition, the inspectors determined the Unit 1 scram procedure did not provide sufficient direction to the operators to control water level and thus prevent a reactor vessel overfill, despite the fact that an appropriate procedure was developed for Unit 2 following an overfill event in January 1988. The above three items are apparent violations of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, and are being considered for escalated enforcement action. (EA 96-541)

O8 Miscellaneous Operations Issues

O8.1 <u>(Closed) URI 50-410/95-16-02: Shift Staffing - Shift Technical Advisor as Reactor Operator Under Instruction</u>

In July 1995, during a review of Unit 2 control room logs, the NRC inspectors identified that on at least two occasions the Shift Technical Advisor (STA) duties and responsibilities were transferred to the Assistant Station Shift Supervisor (ASSS). The ASSS performed the dual role of ASSS/STA. The STA assumed the Reactor Operator Under Instruction (RO U/I) watch to conduct control rod manipulations in anticipation of starting a training class for a senior reactor operator (SRO) license. Unit 2 TS require the presence of an STA during power operations. In addition, the TS state that the STA shall normally be a dedicated position. Although the ASSS met all the requirements necessary for performing the duties of the STA, formal certification of the qualification did not exist; NMPC documented this in DER 2-95-2088. Subsequently, all ASSSs who were qualified were formally certified to perform the STA function.

Failure to have a certified STA on shift during power operations is a violation of Unit 2 Technical Specification, Section 6.2.2.a. Based upon the immediate corrective actions and the availability to meet the minimum crew compliment, this NRC identified violation is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

The Station Shift Supervisor (SSS) inappropriately used the guidance in procedure N2-ODP-OPS-0101, "Operations Policy for Emergency Procedures," Revision 00, to realign the control room staff and allow the STA to conduct reactivity maneuvers for SRO qualifications. N2-ODP-OPS-0101, Section 3.3.4. allowed a Shift Emergency Plan Coordinator (SEPC) to be used if a dedicated STA could not be staffed. NMPC was in the process of deleting the role of SEPC from administrative procedures, but the SEPC had not yet been removed from N2-ODP-OPS-0101. The inappropriate use of N2-ODP-OPS-0101 resulted in the violation discussed above.

DER 2-95-2088 indicated that one apparent root cause for the event was inadequate procedure change management, in that guidance for the use of a SEPC was not expeditiously removed from all administrative procedures. In response to the DER, NMPC removed the description of the SEPC from all procedures. The inspectors consider the root cause evaluation and the corrective actions appropriate.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (61726, 62707)

M1.1 General Comments

Using NRC Inspection Procedures 61726 and 62707, the inspectors periodically observed the licensee perform plant maintenance activities and conduct various surveillance tests. In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures in use at the work site, and with the appropriate focus on safety. Specific activities and observations are detailed below. The inspectors reviewed procedures and observed portions of the following maintenance/surveillance activities:

- N2-OSP-RDS-@001 — Unit 2 Control Rod Stroke Timing and Coupling Verification
- WO 96-08057-00 — Unit 2 Replacement of Reactor Protection System (RPS) Relay K14J
- N2-STP-046 — Unit 2 Single Feedwater Pump Flow Capability Testing
- N2-OSP-EGS-M@001 — Diesel Generator and Diesel Air Start Operability Test - Division I and II
- N1-ST-M6 — Core Spray Keep-Fill System
- N1-ST-Q1A(B) — Core Spray Loop 11(12) Pumps and Valves and Shutdown Cooling Water Seal Check Valves Operability Test
- N1-IPM-CAL-005 — Pressure Regulator Calibration
- N1-ST-M4 — EDGs / PB102 and 103 Operability Test

M1.2 Unit 1 Emergency Diesel Generators and Power Board 102/103 Operability Testing

a. Inspection Scope

On November 26, 1996, the inspectors observed the control room operators perform a surveillance procedure for the emergency diesel generators (EDGs) and vital power boards (PBs). Specifically, the inspectors observed procedure N1-ST-M4, "EDGs/PB102 and 103 Operability Test," Revision 24, Section 8.3, "Diesel Generator 103 One Hour Performance Run."

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

b. Observations and Findings

The inspector observed operations staff perform the surveillance in the Unit 1 Control Room. The operators conducted the following evolutions:

- EDG operability checks prior to load run,
- remote starting of EDG 103 and verification that the EDG obtained proper speed and voltage in allowable time,
- synchronizing of the EDG 103 with Power Board 103, and
- EDG load run

The operations were performed carefully and without difficulty, the inspectors identified no safety concerns. Communications between the operators in the turbine building and the control room were adequate, with no miscommunications identified. Through discussions, the inspector noted that the NMPC staff appeared to understand the scope of the surveillance test and accomplished the evolution without incident.

c. Conclusions

The inspectors determined that the operators were knowledgeable of the requirements of the surveillance test and generally performed all aspects of the EDG surveillance well.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Deficiencies Noted During Core Spray System Walkdown

a. Inspection Scope

During the inspectors' walkdown of the CS system (see Section O2.2), several maintenance deficiencies were noted in the plant and while reviewing historical surveillance test results. The tests reviewed were N1-ST-M6, "Core Spray Keep-Fill System," Revision 07; N1-ST-Q1A(B), "Core Spray Loop 11(12) Pumps and Valves and Shutdown Cooling Water Seal Check Valves Operability Test," Revision 05; and N1-IPM-CAL-005, "Pressure Regulator Calibration," Revision 01.

b. Observations and Findings

Material weaknesses were noted around valve 40-12 (CS Loop 11 inlet to drywell, outside isolation valve). The valve, a normally open motor-operated gate valve, had a catch containment underneath and appeared to have packing leakage. Water was sitting in the valve bonnet below the yoke. A review of surveillance procedure N1-ST-Q1A, indicated that the valve had a minor packing leak in July 1996. NMPC tried to adjust the packing at that time (WO 96-00555-00), but was unable to stop the leak. Valve 40-12 is scheduled to be repacked during the next refueling outage, planned for March 1997.

The inspectors noted that during performance of N1-ST-Q1A on September 9, 1996, the licensee identified packing leakage on valves 40-54 and 40-55, the inboard drain valves for valve 40-12. These valves are in series and are normally closed globe valves. Packing leakage from both valves indicated potential seat leakage past both, since both valve packings were exposed to system pressure. Valves 40-56 and 40-57, the outboard drain valves, also appeared to have had significant packing leakage, as evidenced by corrosion buildup. Valve 40-57 had excessive corrosion surrounding the valve stem and valve bonnet. The inspectors discussed these issues with the system engineer. The inspectors noted that N1-ST-Q1A did not indicate whether the valve packings had been adjusted or if the leakage stopped, nor were problem identification reports issued to address the degradation of any of these valves. After the inspectors brought this to their attention, the licensee initiated a problem identification report for the deficiencies.

The inspectors reviewed four years of completed Instrument & Control (I&C) calibration procedure N1-IPM-CAL-005 test results for the eight CS system pressure control valves (PCV 81-53 through 81-60). The PCVs supply cooling water to the lubricating oil system and seals of the CS pumps and CS topping pumps. The calibration periodicity for these valves was every two years. In 1992, seven of the eight PCVs "as-found" values were out-of-tolerance. In 1994, PCVs 81-57 through -60 were identified as out-of-tolerance low. In 1996, PCV 81-57 was again out-of-tolerance low. The inspectors discussed the issue of continuing out-of-tolerance "as-found" conditions with I&C supervision. The supervisor stated that the 1992 surveillance test was the initial calibration of the eight PCVs. As-found improvement was noted in 1994 and further improvement in 1996. The supervisor discussed the adverse trend with the maintenance manager. DER 1-96-3187 was initiated to address the adverse trend on PCV 81-57.

During the PCV calibrations per N1-IPM-CAL-005, when an out-of-tolerance condition was identified, the calibration procedure required adjusting the setpoint to reestablish the required tolerance. However, there was not a process to trend the out-of-tolerance as-found conditions. Although the inspectors did not identify any system operability issues, they questioned whether this could result in system reliability and surveillance periodicity to be in doubt. The inspectors determined, after discussions with the system engineer and I&C supervision, that no one organization had responsibility for trending of system/component reliability to identify adverse trends, especially when identified during routine calibration. This programmatic issue was to be incorporated into the corrective actions for DER 1-96-3187. Pending the completion of the corrective actions for the DER, and NRC review, this will remain as an inspector follow item. **(IFI 50-220/96-13-02)**

c. <u>Conclusions</u>

No significant equipment deficiencies or operability concerns were identified with the CS system. Some valves were noted to have leakage during past surveillance tests, and other valves that leaked were neither documented nor corrected. An adverse trend was identified by the inspectors on the PCVs for the CS system

pumps, most likely resulting from NMPC not trending as-found conditions during calibrations.

III. ENGINEERING

E1 Conduct of Engineering

E1.1 Missed Inservice Inspection Augmented Weld Inspections

a. Scope

NMPC identified several welds at both units that had not been inspected at the frequency required by the inservice inspection (ISI) program. The welds in question required augmented inspections for intergranular stress corrosion cracking (IGSCC), but were not properly incorporated into the ISI program during the evaluation of NRC Generic Letter (GL) 88-01, "NRC Position on IGSCC in BWR [boiling water reactor] Austenitic Stainless Steel Piping."

The inspectors reviewed related DERs, plant drawings, selected portions of the ISI programs, correspondence related to GL 88-01, completed inspection results, and Unit 1 Licensee Event Report (LER) 50-220/96-08. Additionally, the inspectors had discussions with both plant managers, the engineers responsible for the ISI programs, and the engineering supervisor performing the causal factor analysis for the missed augmented inspections.

b. Observations and Findings

Unit 1

During planning activities for Unit 1 RFO15, scheduled to start March 1, 1997, the maintenance planner noted that an augmented inspection for a core spray system weld had not been included in the outage schedule. The discrepancy was documented in DER 1-96-2286, dated September 24, 1996. Subsequent evaluation by NMPC identified four other welds in the core spray system that had not been inspected at the required frequency of every two refueling outages. One weld was not inspected during either RFO11 (December 1987 to July 1990) or RFO12 (February to April 1993), and four of the welds were not inspected during either RFO12 or RFO13 (February to March 1995). On September 26, 1996, Unit 1 management determined that the plant was not in compliance with TS 4.2.6.a.2, which requires ISI of piping identified in GL 88-01. This issue was subsequently documented in LER 50-220/96-08, "Violation Involving Missed Augmented Inspection Caused by Inadequate Change Management;" the adequacy of the LER is described in Section E8.3.

On November 5, 1996, Unit 1 began a forced outage following a reactor trip. During the outage, NMPC satisfactorily completed the inspection of the five welds that were not previously performed. Additionally, NMPC completed a preliminary

review of other systems associated with Generic Letter 88-01. This review identified welds within the reactor recirculation system that had not been inspected within the required periodicity. The NRC safety evaluation, dated June 24, 1991, stated that Unit 1 had an augmented ISI program to inspect six of the thirty welds between the pumps or valves and the recirculation system piping each refueling outage. One reactor recirculation system weld was not inspected as required during RFO11, four were missed during RFO12, and three were missed during RFO13. Therefore, NMPC determined that eight welds in the reactor recirculation system needed to be inspected to be in compliance with GL 88-01. NMPC completed satisfactory inspections of these welds during the forced outage.

Unit 2

During review of LER 50-220/96-08, the Unit 1 SORC determined that Unit 2 should be informed so that their ISI program could be reviewed for similar problems. NMPC Quality Assurance (QA) performed a surveillance (96-0286-2) focusing on the proper incorporation of Generic Letter 88-01 welds into the Unit 2 ISI program. During the surveillance, a discrepancy was identified in the categorization of several reactor water cleanup (RWCU) system welds, and the completion of the required periodic inspections; this was documented in DER 2-96-2938. The Unit 2 ISI program plan (NMP2-ISI-002, Revision 4) incorrectly indicated the IGSCC Category of 15 RWCU system welds as Category A, instead of Category D, and one weld that should have been classified as Category D was not categorized at all. Category A welds require 25% of the welds to be examined every 10 years, where as Category D welds require inspection every other refueling outage. The Category D inspections should have started with RFO2. NMPC reviewed the inspection history associated with these welds and determined that none of the welds in question were examined during RFO2 or RFO3. During RFO4, four of the welds were examined with satisfactory results. Since Unit 2 was shut down for RFO5 when the discrepancies were identified, NMPC completed the required inspections on the 12 RWCU welds not previously examined.

The inspectors reviewed DER 2-96-2938, and discussed the issue with the engineer responsible for the Unit 2 ISI program. During the discussion the inspectors compared the data in the ISI program plan and the applicable plant drawings to confirm the QA-identified discrepancy. Additionally, the inspectors verified that required augmented inspections of RWCU welds were completed between RFO4 and RFO5. The inspectors also verified that ultrasonic inspections for the 12 welds completed during RFO5 were acceptable. Discussions with the engineer indicated that the ISI program needed to be corrected and that the inspection scheduling will need to be changed to reflect the required inspection frequency.

The root cause of the missed augmented inspections is still being reviewed by NMPC. However, their preliminary cause was that commitments to change the category of the RWCU welds were not incorporated into the Unit 2 ISI program. This commitment was documented in a February 13, 1992, letter from NMPC to the NRC. Specifically, the letter stated that the RWCU welds should be Category D, but

the welds were in the program as Category A. Category A allowed the welds to be inspected every 10 years.

Furthermore, the licensee determined during their review that the above letter was technically incorrect. First, it stated that the RWCU system welds were located outboard of the containment isolation valves (CIVs); in fact, the welds are located inboard of the CIVs. Second, the letter stated that a minimum of 10% of the RWCU system welds in question would be inspected each refueling outage; however, the requirement for Category D welds is that each weld is to be inspected every other refueling outage. Discussions with the NMPC Licensing Manager indicated that the information in the letter would be corrected. The inspectors consider the inconsistencies and inaccurate information in the letter may have contributed to the inspections being missed at Unit 2.

Summary

The failure to complete the required inspections of the Unit 1 CS and reactor recirculation system welds, as required by GL 88-01, is a violation of Unit 1 TS 4.2.6.a.2. Unit 2 TS 4.0.5.f requires the ISI program for piping, identified in NRC GL 88-01, be performed in accordance with the staff position on schedules, methods, personnel, and sample expansion. The failure to complete all Category D inspections of the Unit 2 RWCU system welds, as required by GL 88-01, is a violation of Unit 2 TS 4.0.5.f.
(VIO 50-220/96-13-03 and 50-410/96-13-03)

c. Conclusion

The inspectors considered the questioning attitude demonstrated by the Unit 1 outage planner in identifying that one weld was not scheduled for inspection to be very good. NMPC's review of the remainder of the GL 88-01 program for similar problems at both units was appropriate.

However, the inadequate incorporation of the requirements of GL 88-01 into both of the NMPC ISI programs resulted in the failure to perform numerous TS required augmented weld inspections. The inspectors consider the inconsistencies and inaccurate information in the February 13, 1992, letter may have contributed to the inspections being missed at Unit 2.

E2 Engineering Support of Facilities and Equipment

E2.1 Hot Shorts Vulnerability in Unit 1 Motor Operated Valves

On November 1, 1996, NMPC notified the NRC that Unit 1 may have operated outside its design basis from March 3, 1982, the time NRC approved Appendix R to 10 CFR 50, until February 1995. During this period, a hot short condition could have caused two shutdown cooling system containment isolation valves to be driven closed and bound mechanically, such that the valves would not have been

able to be opened by their motor operators. The valves would need to be opened within 72 hours to achieve a cold shutdown condition.

NMPC's original analysis for this event, in response to NRC Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability during a Control Room Fire," took credit for thermal overloads within the circuit to provide adequate protection. However, a recent analysis of potential hot short problems indicated that the protection provided by the thermal overloads may not be adequate to allow the valves to be opened by normal means after a hot short.

In February 1995, an unrelated plant design change alleviated the potential for a hot short by procedurally maintaining the affected circuit breakers and fuses in a normally deenergized condition. The inspectors verified that the associated valves were deenergized and that adequate procedural controls were in place. This issue remains unresolved pending the completion of NMPC's analysis and subsequent NRC review. **(URI 50-220/96-13-04)**

E8 Miscellaneous Engineering Issues

E8.1 <u>(Closed) URI 50-410/96-11-01: Debris Identified in Suppression Pool Downcomers</u>

a. <u>Inspection Scope</u>

On October 14, 1996, during RFO5, NMPC identified a significant amount of foreign material in the Unit 2 suppression pool downcomers. The amount of material identified was sufficient to potentially clog the emergency core cooling system (ECCS) pumps suction strainers, which may have adversely impacted the operability of the ECCS.

This issue was first described in NRC Inspection Report 50-410/96-11. At that time, an unresolved item was opened to track the issue. The inspectors initially questioned the operability of the suppression pool and the potential negative impact on the ECCS pump suction strainers. Subsequently, the inspectors reviewed the completed NMPC evaluations for suppression pool operability and ECCS pump suction strainer impact. The inspectors also reviewed associated DERs from RFO5 and the last Unit 2 outage (RFO4), various NMPC supporting documents, and related NRC information. The unresolved item is closed; NRC activity will be tracked through the escalated enforcement process (EA 96-474).

b. <u>Observations and Findings</u>

<u>Background</u>

In Spring 1995, during RFO4, NMPC cleaned the suppression pool in expectation of the issuance of related NRC guidance. NRC Bulletin 95-02, "Unexpected Clogging of a RHR [residual heat removal] Pump Strainer While Operating in Suppression Pool Cooling Mode," was issued on October 17, 1995. The efforts during RFO4 did not include an examination of the downcomers. A downcomer is a hollow steel vent

pipe, about 50 feet in length, which penetrates the drywell floor, and connects the drywell atmosphere to the water in the suppression pool. The suppression pool is filled with water and provides for the rapid condensation and cooling of the steam-water mixture which would result from a loss of coolant accident (LOCA). There are 121 downcomers in the Nine Mile Point Unit 2 primary containment; eight of the downcomers are located directly beneath the reactor vessel, inside the pedestal support.

NMPC had planned to conduct an inspection of the suppression pool during RFO5, expecting to find little or no debris because of the cleaning in RFO4. The inspection was performed using a remotely operated submersible camera. On October 14, 1996, the inspection identified a significant amount of foreign material. A diver was contracted to clean the pool; the diver had recently performed a cleaning and inspection of a suppression pool, including the downcomers, at another nuclear power plant. Based on the diver's recommendation, NMPC initiated an examination of the downcomers, using a camera lowered down from the top of the pipe; they found debris in three of the first five inspected. In addition, during the visual examinations, NMPC found that seven of the eight downcomers located in the pedestal support under the reactor vessel appeared to have a hard plastic cover over the top of the downcomer. NMPC believed the covers were left over from initial construction. The visual examinations revealed that most of the downcomers had minimal debris; but 17 had excessive debris (large plastic bags, hard hats, rubber gloves, tygon tubing).

<u>Inadequate Cleaning of the Suppression Pool during RFO4</u>

The work order used during RFO4 (WO 94-07171-00, "Suppression Pool Floor Needs to be Vacuumed and Debris Removed)" was for cleaning the suppression pool floor and the ECCS suction strainers, but did not consider an overall examination of the pool. The inspectors noted during a review of the post-job review associated with WO 94-07171-00 that NMPC recognized the need for improved foreign material exclusion (FME) controls to prevent additional material from entering the suppression pool by means of the downcomers. The inspectors also reviewed DER 2-95-1639, initiated on May 11, 1995, which noted that most of the debris was located in the area beneath the downcomers. NMPC was aware that there was much more material in the suppression pool than they expected. However, the licensee did not initiate an assessment to determine the amount of debris removed and the potential effect on safety related equipment.

While cleaning the pool, NMPC recognized and documented in a DER that most of the material must have entered via the downcomers, but did not initiate an examination of the downcomers at that time. In addition, the NRC had issued guidance regarding the examination of suppression pools and, specifically, the downcomers - NRC Regulatory Guide (RG) 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident." RG 1.82, Revision 0, only discussed pressurized water reactors (PWRs); as such, Unit 2, being a boiling water reactor (BWR), did not commit to the RG in the UFSAR. However, Revision 1, issued November 1985, addressed both PWRs and BWRs. Section

C.2.12(c) of RG 1.82 states: "Inservice inspection requirements should include ... an inspection, for evidence of debris or trash, of the wetwell [suppression pool] air spaces and the drywell floor regions, including the downcomers ..."

The work order developed for cleaning and inspecting of the Unit 2 suppression pool during RFO4 was narrowly focused and did not incorporate available industry information relative to examination of the downcomers. After finding more debris in the suppression pool than expected during RFO4, and noting the debris must have entered the suppression pool via the downcomers, NMPC failed to inspect the downcomers during RFO4. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," and the NMPC QATR, in that controls were not established to assure a condition adverse to quality (i.e., significant amount of debris in the suppression pool) was identified and appropriate corrective action taken. As a result, a significant amount of foreign material was left in the downcomers from June 1995 until October 1996.

Evaluation of Pedestal Downcomers Covers

During the examination of the downcomers, NMPC identified that seven of the eight downcomers in the reactor pedestal support area had a hard plastic cover installed over the top of the downcomer. At NMPC's request, General Electric performed an engineering evaluation of the effect of the downcomers being closed to the suppression pool. The evaluation used a worst case scenario of all eight pedestal downcomers being blocked, and this resulted in a reduction in the downcomer flow area to 93.4% (percent). The effect of this reduced area was an increase in drywell pressure by less than 4%; this equates to a peak drywell pressure of 39 psig (pounds per square inch gage), which is below the containment design pressure of 45 psig. Other potential impacts of the blocked downcomers were also evaluated and found to be conservative or negligible.

As discussed in DER 2-96-2640, NMPC determined that the root cause for the downcomers being covered was that personnel exhibited insufficient awareness of the impact of their actions on nuclear safety, in that during initial closeout, they did not exhibit a questioning attitude. Contributing causes included closeout checklists that did not specifically require an inspection of the downcomers, and insufficient lighting and cramped conditions that were not conducive to inspection in the pedestal area under the reactor vessel.

The inspectors reviewed the guidance provided for drywell closeout inspection contained in N2-OP-101A, "Plant Start-Up," Revision 11. Attachment 2, "Master Startup Checklist," to N2-OP-101A, Section H, "Primary Containment Pre-Startup Check," step 18, requires a detailed inspection of all drywell areas to ensure no loose material existed. A Procedure Change Evaluation (PCE) form was initiated on October 26, 1996, adding a specific verification that all downcomers were open to the drywell atmosphere and free of significant foreign material.

Notwithstanding adequate corrective actions once the downcomer caps were identified, the failure to discover and remove the caps during all drywell closeout

inspections from initial startup until October 1996, is an apparent violation of procedure N2-OP-101A; in that, a detailed inspection of the drywell was not performed to ensure that all loose material was removed prior to startup.

Potential for Clogging of ECCS Pump Suction Strainers due to Debris Found in Downcomers During RFO5

Preliminary analysis by NMPC determined that the design suppression function of the pool would not be exceeded; however, they felt that the potential existed for clogging of the ECCS pump suction strainers. NMPC estimated that 47 square feet (ft^2) of material was available to block the ECCS pump suction strainers. There are five ECCS pumps that take a suction from the suppression pool: the high pressure core spray (HPCS) pump, low pressure core spray (LPCS) pump, and three low pressure coolant injection (LPCI) pumps. In addition, although not an ECCS pump, the high pressure reactor core isolation cooling (RCIC) pump also takes a suction from the suppression pool. The suction strainers for the HPCS pump and the LPCS pump each have a surface area of ≈ 21 ft^2. The strainers for the RCIC pump and the LPCI pumps each have a surface area of ≈ 34 ft^2. The high pressure pumps (HPCS and RCIC) initially take a suction from the condensate storage tank (CST); on a low CST level, the HPCS and RCIC pumps swap suction to the suppression pool. The low pressure pumps only take a suction from the suppression pool.

The final NMPC evaluation for the amount of foreign material removed from the downcomers included an actual determination of how much material was available for clogging of the ECCS pump suction strainers. The NMPC calculation of the amount of material removed was consistent with their initial estimate; i.e., 47 ft^2, or slightly less than 50% of the available strainer surface area.

The Unit 2 UFSAR, Section 6.3, "Emergency Core Cooling Systems," subsection 6.3.2.2, states that sufficient net positive suction head (NPSH) is available for the ECCS pumps if the suction strainers are no more than 50% clogged.

Affect of Material Removed from the Suppression Pool in RFO4

During the review of the completed WO used during RFO4, the inspectors noted that the work supervisor commented on the WO front cover that the amount of debris discovered in the suppression pool was much more than expected. The inspectors questioned NMPC with respect to the types and quantities of material removed from the suppression pool during RFO4. NMPC reviewed the video tapes from the cleaning and compiled a list of material removed; some of the larger items listed included plastic sheeting totalling ≈ 95 ft^2.

This material by itself, but especially combined with the additional material removed in RFO5, was sufficient to potentially clog the ECCS pump suction strainers, which may have adversely impacted the operability of the ECCS.

c. Conclusions

During the Unit 2 fifth refueling outage, the licensee identified a significant amount of foreign material in the Unit 2 suppression pool downcomers. This is significant because the debris could clog the ECCS pump suction strainers and affect the operability of the ECCS systems. The inspectors concluded that the suppression pool was not adequately cleaned during RFO4 in Spring 1995. In particular, the inspectors noted the licensee found more debris in the suppression pool than expected and documented in a DER that the debris removed from the suppression pool during RFO4 probably entered the suppression pool via the downcomers, but failed to inspect the downcomers. This is an apparent violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." In addition, the licensee failed to properly implement the inspection procedure for drywell closeout, to ensure no loose material existed, in that the licensee failed to identify caps on seven downcomers that were apparently left in place since initial startup. The above items are being considered for escalated enforcement action. (EA 96-474)

E8.2 (Closed) LER 50-140/96-11: Potential Blockage of Emergency Core Cooling System Suction Strainers Caused by Inadequate Managerial Methods

The details of this LER are described in Section E8.1 of this inspection report. The LER satisfactorily describes the event. The causes and the corrective actions are detailed and appropriate. The inspectors had no further questions.

E8.3 (Open) LER 50-220/96-08: Violation Involving Missed Augmented Inspection Caused by Inadequate Change Management

The inspectors described the technical details associated with the LER in Section E1.1 of this inspection report. The inspectors considered the LER to be timely and to accurately describe the event. The root cause was not completed at the time the LER was submitted, and four other systems (reactor recirculation, reactor water cleanup, shutdown cooling, and emergency cooling) were still being reviewed for possible missed inspections. According to the LER, a supplement will be provided by December 20, which will include the results of the root cause evaluation and the additional reviews. Therefore, this LER remains open pending the submission of the LER Supplement by NMPC and subsequent NRC review.

E8.4 (Closed) Unit 2 Special Report: Division I Standby Emergency Diesel Generator Non-valid Test and Non-valid Failure

On October 10, 1996, while performing an 18-month surveillance test on the Division I emergency diesel generator (EDG), the acceptance criteria for generator frequency was not achieved. This part of the surveillance test requires the electronic governor be defeated, and the mechanical governor regulate generator frequency. The TS provides frequency requirements for 10 seconds after EDG start, and 13 seconds after EDG start. The 10 second criteria was satisfied; however, the 13 second criteria was not satisfied. At 13 seconds, a frequency of 61.267 hertz was achieved, as compared to an acceptance criteria of 60 $\pm$ 1.2

hertz. The surveillance was repeated satisfactorily with no adjustments made to the mechanical governor. NMPC attributed the slow response of the mechanical governor to the recently completed replacement of the governor oil, at which time air was probably introduced into the governor oil. The air would have vented off during the failed surveillance test, thereby correcting the condition.

NMPC determined that the test was non-valid based on the guidance provided in NRC RG 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants." NMPC noted in the special report that "... the mechanical governor is bypassed in the emergency mode, and therefore, would not prevent the diesel from starting and successfully achieving its loading requirement." The inspectors considered the term "bypassed" to be misleading, the mechanical governor provides a backup to the electronic governor in the emergency mode and is not removed from the circuit as the term "bypassed" could imply. In addition, NMPC informed the inspectors that the mechanical governor is not specifically addressed in the UFSAR and is not considered as part of the design basis for the EDG. The inspectors' review of the failure and the guidance provided in RG 1.108 indicates that NMPC's determination that the failure and test were non-valid was appropriate.

E8.5 Potentially Counterfeit Anderson Greenwood Valves

a. Scope

On June 13, 1996, NMPC was informed by the Department of Defense that some pressure relief valves sold as being manufactured by Anderson Greenwood may be counterfeit. The valves were alleged to contain parts manufactured and sold by Niabco (also known as Nibsco) that were not subjected to the same testing and quality controls as those that legitimately carry the Anderson Greenwood trade name. This concern was documented in DER C-96-1488.

The inspectors assessed NMPC's actions in response to this concern by reviewing applicable documentation and discussing the issue with NMPC personnel from the procurement, operations and engineering departments.

b. Observations and Findings

Upon identification of the concern, NMPC segregated all Anderson Greenwood valves in stock pending the results of the investigation. In addition, the licensee verified that all Anderson Greenwood valves purchased by NMPC were not being used in safety-related applications.

Subsequently, NMPC reviewed their procurement records to determine the location of the valves purchased. Two valves had been installed in the main generator hydrogen system, but were removed in 1993 as part of a design change. Another valve was currently installed in a non-safety application in the Unit 2 generation nitrogen system. The inspectors verified that the only installed valve was utilized in a non-safety application. All other valves were in the NMPC store room.

All valves in the store room were shipped to Anderson Greenwood for inspection. Anderson Greenwood determined that the valves were in accordance with manufacturer's drawings and Niabco's Assembler and Valve Repair Programs. Anderson Greenwood identified only one part was not original Anderson Greenwood. According to Anderson Greenwood, the part in question was a guide, which would not effect the function of the valve. The inspectors reviewed the results of the Anderson Greenwood inspections and identified no concerns.

c. <u>Conclusion</u>

The inspectors concluded that NMPC's actions to address the potentially counterfeit Anderson Greenwood valves were appropriate. No counterfeit valves were identified at Nine Mile Point.

IV. PLANT SUPPORT

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

P8 Miscellaneous EP Issues (TI 2515/134)

During the week of September 30, 1996, a region-based emergency preparedness specialist conducted an in-office telephone interview with NMPC in order to carry out the NRC's Temporary Instruction (TI) 2515/134, "Licensee On-Shift Dose Assessment Capabilities." The goal of the TI was to gather information on the licensee's capability to perform on-shift dose assessment. It was determined that the licensee did have on-shift assessment capability supported by appropriate procedural guidance, and therefore met NRC requirements to be able to perform dose assessment at all times. The results of the evaluation were forwarded to NRC headquarters personnel.

S2 Status of Security Facilities and Equipment

S2.1 <u>Tour of Security Facilities and Protected Area Perimeter</u>

On November 13, 1996, during a tour of the protected area perimeter, the inspectors found the fence and perimeter detection system intact. The inspectors also toured the central and secondary alarm stations and found them appropriately staffed, and the equipment operating properly. The inspectors discussed with a security supervisor the preparations that security made for cold weather conditions. Based on the discussion and a review of applicable procedures, the inspectors considered the cold weather preparations and controls to be appropriate.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on December 20, 1996. Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

ATTACHMENT
PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

R. Abbott, Vice President & General Manager, Nuclear
J. Aldrich, Maintenance Manager, Unit 1
M. Balduzzi, Operations Manager, Unit 1
D. Barcomb, Radiation Protection Manager, Unit 2
C. Beckham, Manager, Quality Assurance
J. Burton, Director, ISEG
G. Correll, Chemistry Manager, Unit 1
J. Conway, Plant Manager, Unit 2
R. Dean, Engineering Manager, Unit 2
A. DeGracia, Work Control & Outage Manager, Unit 1
G. Helker, Work Control & Outage Manager, Unit 2
M. McCormick, Vice President, Nuclear Engineering
L. Pisano, Maintenance Manager, Unit 2
N. Rademacher, Plant Manager, Unit 1
R. Smith, Operations Manager, Unit 2
P. Smalley, Radiation Protection Manager, Unit 1
K. Sweet, Technical Support Manager, Unit 1
C. Terry, Vice President, Nuclear Safety Assessment & Support
K. Ward, Technical Support Manager, Unit 2
C. Ware, Chemistry Manager, Unit 2
W. Yaeger, Engineering Manager, Unit 1

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71714	Cold Weather Preparations
IP 71750:	Plant Support
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 92904:	Followup - Plant Support
TI 2515/134:	Licensee On-Shift Dose Assessment Capabilities

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-220/96-13-01	URI	EC system potentially inoperable due to water in the steam lines
50-220/96-13-02	IFI	No trending of component after being found out of tolerance during calibrations
50-220 & 50-410/96-13-03	VIO	ISI inspections not performed at required frequencies
50-220/96-13-04	URI	Hot shorts vulnerability of shutdown cooling valves
50-220/96-08	LER	Violation involving missed augmented inspection caused by inadequate change management

CLOSED

50-410/95-16-02	URI	Inadequate shift staffing - STA performing duties as RO UI
50-410/96-11-01	URI	Debris identified in suppression pool downcomers
50-410/96-11	LER	Potential blockage of ECCS suction strainers caused by inadequate managerial methods

UPDATED

None

LIST OF ACRONYMS USED

ADS	Automatic Depressurization System
ASSS	Assistant Station Shift Supervisor
BWR	Boiling Water Reactor
CFR	Code of Federal Regulations
CIV	Containment Isolation Valve
CS	Core Spray
CSO	Chief Shift Operator
CST	Condensate Storage Tank
DER	Deviation/Event Report
EC	Emergency Condenser
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
FCV	Flow Control Valve
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
ft^2	square feet
FWP	Feedwater Pump
GL	Generic Letter
gpm	gallons per minute
HPCI	High Pressure Coolant Injection
HPCS	High Pressure Core Spray
IFI	Inspector Followup Item
IGSCC	Intergranular Stress Corrosion Cracking
IR	Inspection Report
ISI	Inservice Inspection
IST	Inservice Testing
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
MSIV	Main Steam Isolation Valve
MSL	Main Steam Line
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NR	Narrow Range
NRC	Nuclear Regulatory Commission
PB	Power Board
PCE	Procedure Change Evaluation
PDR	Public Document Room
PCV	Pressure Control Valve
psig	pounds per square inch gage
QA	Quality Assurance
QATR	Quality Assurance Topical Report
RCIC	Reactor Core Isolation Cooling
RCS	Recirculation System
RFO	Refueling Outage
RG	Regulatory Guide

RHR	Residual Heat Removal
RO	Reactor Operator
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Clean-Up
SORC	Station Operations Review Committee
SRO	Senior Reactor Operator
SSS	Station Shift Supervisor
STA	Shift Technical Assistant
TI	Temporary Instruction
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WO	Work Order
WR	Wide Range