U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	July 23 to September 2, 1995
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/95-18 & 50-410/95-18
July 23 to September 2, 1995

PLANT OPERATIONS

During this inspection period, Unit 1 operated at essentially full power. Unit 2 was limited during much of the period due to oscillations of a turbine control valve and a recirculation flow control valve. On September 1, during a planned shutdown, high vibration was noted on the main turbine and a manual scram was inserted. The period ended with Unit 2 in a forced outage.

The inspectors reviewed the refueling activities at both units. They determined that both units have established procedural controls consistent with their respective Final Safety Analysis Reports (FSARs) and Technical Specifications (TSs) for refueling operations involving a full core offload.

On September 1, the Unit 2 operators manually scrammed the reactor in response to increasing main turbine vibration. The inspectors considered the response of the control room crew to be appropriate and noted that the supervisors exhibited good command and control. After the scram, all control rods but one indicated "Full-In." Subsequent NMPC review confirmed the control rod properly inserted and within the required time. Further review by NMPC determined that the same control rod exhibited similar behavior during a scram earlier this year. Subsequent to the end of this inspection period, the position indication for the control rod again lost during a plant shutdown. The inspectors are concerned that the continuing failure of the control rod position indication, combined with the failure of another rod to indicate "Full-In" following a scram, would require unnecessary actions within the EOPs which could complicate the operators' response to a plant transient.
(URI 50-410/95-18-01)

MAINTENANCE

The inspectors observed maintenance activities and noted no problems. Also, a review of several safety related work packages identified that all had the appropriate documentation, including the proper verifications and material control.

The inspectors reviewed the maintenance open work order and deficiency backlog for both units and concluded that management was prioritizing and completing work to ensure appropriate safety equipment performance and reliability. The positive trend for total number of backlog items continues. Maintenance work was appropriately identified, prioritized, and completed to maintain safety system readiness.

ENGINEERING

NMPC was discovered that Unit 1 the computer indication of feedwater flow was not consistent with the design calculations. NMPC's review identified two

EXECUTIVE SUMMARY (continued)

separate problems, both of which were in the non-conservative direction; the computer truncated the conversion factor for flow and a previous calibration of the feedwater flow transmitters contained an error. The composite resulted in a total error of 1.363 MWt, or approximately 0.07% of rated core thermal power above the license limit. The combined error is a small fraction of the allowed thermal power, less than the uncertainty applied to the calculation. The violation was not cited.

Unit 2 operations and engineering personnel responded quickly to a high pressure core spray (HPCS) unit cooler operability concern. An operator noted that the service water inlet temperature was above the established limit of 76.6 degrees Fahrenheit (°F), rendering the HPCS system inoperable. The engineering support analysis and operability review determined that the associated unit cooler was operable up to a service water (SW) temperature of 80.7°F with the same SW flow.

Engineering revised the list of Unit 2 primary containment isolation valves to include 4 valves in the standby liquid control system. Two weeks later, it was noted the valves had not been included during the latest performance of the surveillance test. Subsequently, the Unit 2 station operations review committee (SORC) determined that the current configuration met the requirements of GDC #55, and thus the SLC vent and drain valves were not required for primary containment. The NRC expressed concern that the list of containment isolation valves and the related surveillance procedure were changed unnecessarily and without full evaluation by the operations department. **(URI 50-410/95-18-02)**

PLANT SUPPORT

The inspectors toured the normally locked areas of the Unit 1 radwaste facility and noted that the pumps and valves were in relatively good condition. The general area was clean, decontaminated as much as practical, spray painted, and easily accessible wearing only protective shoe covers and gloves. A radiation protection technician conducted a thorough pre-evolution brief including the general layout of the area, and the anticipated radiation and contamination levels in the radwaste building.

The inspectors the periodic EP drill conducted on August 8. Generally, the inspectors considered that the Nine Mile staff performed well during the drill, and that their actions would be adequate to protect the health and safety of the surrounding public. The licensee's performance was improved since the last NRC observed exercise. The inspectors attended the licensee's drill critique and determined it was effective. The licensee noted some areas for improvement. Senior station management was present at the critique.

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DETAILS

1.0 SUMMARY OF ACTIVITIES

NMPC Activities

During this inspection period, Nine Mile Point Unit 1 (Unit 1) operated at full power with only minor power reductions for maintenance and control rod pattern adjustments. Unit 2 started the period at 98%, limited in power due to oscillations of the #4 turbine control valve. On August 1, the "B" recirculation flow control valve started to exhibit some oscillations in valve position, causing subsequent cycles in power. Operators placed the valve in manual and reduced power to about 95%. After attempting several unsuccessful alternative measures to provide adequate control of the valve, management decided to shutdown the unit for repair. On September 1, a plant shutdown was in progress, when high vibration was noted on the main turbine; the operators inserted a manual scram. The period ended with Unit 2 entering a forced outage for repairs to the flow control valve, and other equipment.

NRC Activities

The inspectors conducted inspection activities during normal, backshift, and weekend hours. Specialist inspections conducted during the period included the areas of radiological controls, emergency preparedness, confirmatory measurements, and effluents. The results of these inspections will be documented and reported separately.

2.0 PLANT OPERATIONS (71707, 92901, 93702)*

2.1 Operational Safety Verification

The inspectors observed overall operation and verified that Niagara Mohawk Power Corporation (NMPC) operated the units safely and in accordance with their procedures and regulatory requirements. The inspectors conducted regular tours of all accessible plant areas. The tours included walkdowns of safety systems and components for leakage, lubrication, cooling, and general material conditions that might affect system operation. No significant deficiencies were noted, minor deficiencies were discussed with the appropriate management.

2.2 Review of Spent Fuel Pool Basis for Full Core Offload

Recently, it was identified that another facility routinely unloads the entire reactor core during refueling operations. However, their Final Safety Analysis Report (FSAR) only provided an analysis for a normal 1/3 core offload. Based on this event, and considering that both units recently completed refueling outages utilizing a full core offload, the inspectors compared the NMPC refueling practice against the FSAR for both units.

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

Unit 1

The Unit 1 FSAR, Section X.H.1.0, Spent Fuel Storage Pool Filtering and Cooling System, discusses the precautions and limitations associated with various options for refueling; specifically, a normal core shuffle, a normal full core offload, and an abnormal maximum heat load case such as a full core offload shortly after refueling. Each case requires a verification that offload time and reactor building closed loop cooling temperature would be consistent with a pool temperature of less than 125°F (degrees Fahrenheit). NMPC has a procedure to address the case of a full core offload. The procedure includes a precaution that states commencing core offload prior to 3½ days after reactor shutdown or offloading too quickly may violate the assumptions used in the decay heat removal analysis for spent fuel pool cooling.

Unit 2

The Unit 2 FSAR, Sections 9.1.3, Spent Fuel Pool Cooling and Cleanup System, and 9.1.4.2.11, Fuel Handling, describe a normal refueling outage as approximately 25 to 33 percent of the fuel being removed from the reactor vessel and the remaining fuel being reshuffled in the vessel. The FSAR also describes in detail the option of a full core offload. In practice, Unit 2 has performed only full core offload during refueling outages. Guidance regarding full core offload is provided in procedure N2-FHP-13.1. Currently, Unit 2 has no procedures developed for a one-third core offload in conjunction with a fuel shuffle. Discussions with NMPC indicated they are in the process of developing a procedure for future use.

The inspector determined that both units have established procedural controls consistent with their respective FSARs and TSs for refueling operations involving a full core offload. There were no further questions.

2.3 Unit 2 Reactor Scram During Plant Shutdown

On September 1, 1995, the Unit 2 operators manually scrammed the reactor in response to increasing main turbine vibration. Prior to the event, they were in the process of shutting down the plant in preparation for an outage to repair the "B" recirculation flow control valve. The reactor was at 26% power at the time of the scram. All safety systems functioned as design. However, the position indication for control rod 26-19 did not function immediately following the scram. The operators responded promptly and properly to stabilize the plant in a hot shutdown condition.

During the shutdown, while decreasing reactor power and shifting reactor recirculation pumps to low speed, turbine bearing vibration began to quickly increase. A turbine high vibration alarm was received when bearing #6 vibration exceeded 7 mils. Vibration continued to increase, and at 11.5 mils, a manual reactor scram was ordered by the station shift supervisor (SSS). Approximately 4 seconds following the reactor scram, the turbine tripped on high vibration. High vibration, but less severe, had also been experienced earlier during the shutdown.

The inspectors observed the control room crew after the scram, and considered their response appropriate. The control room supervisors exhibited good command and control. The inspector reviewed the Post-Scram Review, performed in accordance with Procedure N2-REP-6, and found it to be appropriate.

After the scram, all control rods immediately indicated "Full-In" except for rod 26-19, which did not indicate for approximately five minutes. Subsequent investigation by NMPC determined that control rod 26-19 fully inserted within the required time following the scram, and that only the rod position indication was temporarily lost. A problem identification report was written to troubleshoot and repair the position indication. The same control rod exhibited similar behavior during a scram earlier this year. Also, a deviation/event report (DER) was written to address the problem with the rod position indication.

Subsequent to the end of this inspection period, the inspectors noted that position indication for control rod 26-19 was again lost during a plant shutdown, after the mode switch was taken to the "Shutdown" position. Based on the recurrence of this problem, the inspectors are concerned that the continuing failure of the control rod 26-19 position indication, combined with the failure of another rod to indicate "Full-In" following a scram, would require unnecessary actions within the emergency operating procedures (EOPs) which could complicate the operators' response to a plant transient. The inspectors were also concerned that this problem was not aggressively pursued after it first appeared earlier this year. This issue remains unresolved pending the NRC review of the disposition of the DER. **(URI 50-410/95-18-01)**

3.0 MAINTENANCE (61726, 62703, 92902, 60705)

3.1 Maintenance and Surveillance Observations

The inspectors observed maintenance and surveillance activities to ascertain if safety-related work was conducted according to approved procedures, the TSs, and the appropriate industry codes and standards. Observation of activities verified that: LCOs were satisfied, removal and restoration of equipment were controlled, administrative authorizations and tag outs were obtained, procedures were adequate, certified parts and materials were used, test equipment was calibrated, radiological requirements were implemented, system prints and wire removal documentation were used, quality control hold points were established, deficiencies were documented and resolved, and records were complete and accurate. In general, the activities observed and reviewed were effective with respect to meeting the safety objectives. No significant concerns were identified during the inspectors' review.

The inspectors reviewed a number of safety related work packages completed during the inspection period and noted that all had the appropriate documentation of work, including proper verifications and material control. For Unit 1, eight of the packages involved repair of emergency lights and four of these required battery replacement as the repair, two required circuit repair, and two deficiencies could not be replicated and the work package was closed with no emergency light repair required. The selected maintenance items were well controlled with appropriate safety focus and documentation met station requirements. No safety concerns were identified.

Other work packages reviewed included:

Unit 1

WO 95-2655 Tighten packing to reduce leakage on an equalizing valve to the reactor vessel level instrumentation transmitter supply lines.

WO 95-2661 Replace leaking valve on the instrument air drain line.

Unit 2

WO 95-8602 Repair of standby gas treatment pressure control valve control circuit cooling fan. The deficiency was identified on October 2, 1993 and repaired on August 15, 1995, and involved replacement of a cooling fan assembly. Operability of the standby gas treatment system was not affected by the deficiency.

WO 95-7781 Loop calibration of 2SWP-PT45, service water pressure transmitter

WO 95-7778 Loop calibration of the division II, emergency diesel generator fuel oil level switch

3.2 Maintenance Backlog Review

Unit 1

The inspectors reviewed the Unit 1 maintenance open work order and deficiency backlog and concluded that management was prioritizing and completing work to ensure appropriate safety equipment performance and reliability. In early 1995, Unit 1 had established a goal of less than 450 total non-outage corrective maintenance items in the backlog. At the time of the inspection, the backlog was approximately 500 items; the list included safety related equipment deficiencies, radwaste, fire protection, and other non-power production items. Since setting the goal, a positive backlog reduction trend had been achieved, with an average monthly reduction of about 35 items.

The inspector reviewed the backlog of safety related corrective maintenance work orders. Of the 82 total items reviewed, none were identified as affecting the operability or readiness of safety equipment. Additionally, of the 44 items on the plant deficiency list, none were identified as safety system operability or readiness concerns. In addition, the inspector conducted a check of the backlog for fire protection, fuel oil handling and storage, and emergency diesel generator cooling water systems. Only low priority items were found; none involved operability issues. No discrepancies between the backlog and the individual system lists were identified.

The inspector considered the ability of the staff to identify and repair plant deficiencies, and the program overall, to be well organized and effective. Plant deficiencies were found to be identified during operator walkdowns, surveillance testing, and management housekeeping tours. Once identified, the deficiencies were tracked until work orders were prepared, then the work orders were tracked to completion. In conclusion, Unit 1 was determined to have appropriately identified, prioritized, and completed maintenance work items to maintain safety system readiness.

Unit 2

In a review of the Unit 2 non-outage corrective maintenance backlog, it was determined that the facility had appropriately prioritized work to ensure safety system readiness and operability. At the time of the inspection, the corrective maintenance backlog contained 1062 work orders and plant deficiencies, including radwaste and fire protection items. Unit 2 had established a goal to reduce the total backlog to less than 750 items by the end of 1995, and initiated a "Fix-It-Now" program to assist in achieving the goal. The initiative will allow work groups to make minor, non-safety related repairs to identified deficiencies with only minor involvement of the planning and scheduling departments.

The inspectors further conducted a detailed review of safety related plant deficiencies and work orders and found no instances involving equipment operability or readiness. A number of items greater than one year old were identified; however, facility initiatives to reduce the overall backlog appeared to appropriately prioritize work with a proper safety focus. In conclusion, the inspectors found that Unit 2 appropriately prioritized maintenance items to ensure plant safety and had taken a number of initiatives to streamline maintenance to reduce the overall maintenance backlog.

4.0 ENGINEERING (37551, 92903, TI 2515/128)

4.1 Unit 1 Core Thermal Power Limit Exceeded

In 1991, a deviation/event report (DER) was written at Unit 1 which identified that computer points associated with the feedwater flow differential pressure transmitters were not properly reflected on the drawings. The root cause for the problem was a poor configuration and design control program, in effect at that time, for the drawings associated with plant process computer. The DER was dispositioned in early 1994, and the drawings were corrected to reflect actual plant configuration. Also, unrelated to the DER, NMPC modified the feedwater flow transmitters associated with the computer to enhance performance.

In June 1995, during post-modification testing, it was discovered that the computer calculation of feedwater flow was not consistent with the design calculations. A review of the system software identified that the computer could not store the conversion factor with sufficient resolution; i.e., the conversion factor was rounded-off. This resulted in actual core thermal power exceeding indicated power by 0.37 megawatts thermal (MWt). While correcting the process computer error, the feedwater flow transmitters were also recalibrated. A subsequent manual heat balance was inconsistent with the process computer calculation of core thermal power. An investigation by NMPC revealed that the previous calibration (November 1992) contained an error for one of the flow transmitters, resulting in actual power exceeding indicated power by 0.993 MWt. The composite resulted in a total error of 1.363 MWt, or approximately 0.07% of rated core thermal power.

The corrective actions included an immediate reduction in reactor power and an administrative limit to ensure that indicated power is maintained below the license limit of 1850 MWt. A design change was initiated to eliminate the truncation error, and the flow transmitters were recalibrated per a revised procedure.

The inspectors reviewed the initial DER and the related corrective actions, and the subsequent actions related to the operation in excess of rated thermal power. The inspector considered the immediate actions and those taken to prevent recurrence appropriate and adequate. This is a violation of the maximum core thermal power specified in the Core Operating Limit Report per TS 3.1.7.d. The combined error is a small fraction of the allowed thermal power, is less than the uncertainty applied to the calculation assuming all other elements of the measurements are accurate, and is bounded by the safety analysis of the Final Safety Analysis Report. This violation was not cited in accordance with the NRC Enforcement Policy, as described in NUREG-1600, Section VII.B.1.

4.2 High Pressure Core Spray Potentially Inoperable - Unit 2

On July 27, Unit 2 operations and engineering personnel responded quickly to a high pressure core spray (HPCS) unit cooler operability issue. During rounds, an operator noted a service water (SW) inlet temperature above 76.6°F (degrees Fahrenheit), as indicted in the control room. The station shift supervisor (SSS) declared the HPCS system inoperable, due to the SW temperature exceeding a previously determined limit for the unit cooler in the HPCS switchgear room. Operators documented the issue on a deviation/event report (DER), made the appropriate notification to the NRC operations center per 10CFR50.72, and requested engineering to perform an operability evaluation.

The inspectors noted that a surveillance test conducted several weeks earlier had established the 76.6°F temperature limit. During the surveillance test, the SW flow to the unit cooler from Division I was 10.4 gallons per minute (gpm). Based on conservative assumptions, at a SW temperature of 82°F, a minimum SW flow of 16 gpm was required to dissipate the design heat load. If flow rates and temperatures are lower than the design assumptions, the surveillance procedure provides a temperature versus flow curve to evaluate the ability of the cooler to remove its design heat load. With a measured flow of 10.4 gpm, the graph indicated a maximum SW temperature of 76.6°F. Operators noted the operational limit in the logs and made the appropriate entry in the equipment status log for the HPCS unit cooler.

The engineering support analysis checklist and operability review, dated July 27, 1995, determined that the HPCS switchgear unit cooler was actually operable up to a SW temperature of 80.7°F with the 10.4 gpm flow. Engineering used the actual unit cooler fouling factor developed during the February 1995 cooler performance testing. The analysis showed that a flow of 10.4 gpm, at a service water temperature of 80.7°F, could remove more than the required design heat load. The determination that 10.4 gpm from the Division I source was acceptable was based on (1) check valve testing conducted on the Division II source, which yielded 13.5 gpm, and (2) engineering judgement that the two sources combined would yield a flow greater than the 16 gpm for a normal SW operational alignment. Further, if the Division II supply were lost due to a design bases loss of coolant accident coincident with a loss of offsite power, the cooler would receive more than 10.4 gpm, since system requirements would be considerably less due to non-safety component isolation. Based on the engineering analysis, the operators declared the cooler and HPCS system operable.

The inspectors reviewed the assumptions and calculations, and determined that the analysis reflected the best information available on the capability of the unit cooler to remove heat. The inspector considered the calculations and the associated engineering analysis to be acceptable.

4.3 Unit 2 Containment Isolation Valve List Changed Incorrectly

On August 7, 1995, engineering revised the list of Unit 2 primary containment isolation valves, M2-0001, to include four valves (vents and drains) in the standby liquid control (SLC) system. This list is the controlling document for operations surveillance test procedure N2-OSP-CNT-M001, "Primary Containment Penetration Verification Test." The monthly test satisfies the surveillance requirements of TS 4.6.1.1, which verifies every 31 days that primary containment isolation valves are shut. On August 21, it was noted by the Station Shift Supervisor (SSS) that the four SLC valves had not been included during the latest performance of the surveillance test. The last time that the SLC valves had been verified shut was in May 1995. Immediate corrective actions included a valve lineup of the SLC system to verify that the four valves were in the correct position, and generation of a deviation/event report (DER 2-95-2415). The inspectors reviewed the event and considered the immediate corrective actions appropriate and adequate.

Subsequently, on September 15, the Unit 2 station operation review committee (SORC) reviewed a safety evaluation (SE) related to the containment isolation valves for the SLC system. The SE described that the current configuration met the requirements of general design criteria #55 (10 CFR 50, Appendix A). Thus, the SLC vent and drain valves were not required for primary containment. The inspector expressed concern that an engineering list and the related controlling procedure for surveilling the primary containment valves could be changed unnecessarily and without full evaluation by the operations department. This item will remain unresolved pending further NRC review. **(URI 50-410/95-18-02)**

5.0 PLANT SUPPORT (71707, 71750, 92904)

5.1 Observations of Plant Support Activities

The inspectors routinely monitor activities in the areas of radiation protection, emergency preparedness, security, fire protection, and general housekeeping during tours. Minor weaknesses were discussed with the appropriate supervision, no significant deficiencies were noted.

5.2 Tour of Unit 1 Radwaste Facility

On August 4, the inspector performed a tour of the normally locked areas of the Unit 1 radioactive waste (radwaste) facility. A radiation protection (RP) technician conducted a thorough pre-evolution brief including the general layout of the area, and the anticipated radiation and contamination levels in the radwaste building. The RP technician also accompanied the inspector and the Radwaste Supervisor on the tour, ensuring that the surveys performed several weeks earlier were still accurate.

The inspector noted that the pumps and valves were in relatively good condition and the general area was clean and mostly uncontaminated. Over the last several years, extensive effort was expended in cleaning up the radwaste area, especially the 225' elevation. The entire 225' elevation was previously highly contaminated, with excessive amounts of material stored in the area. The inspector observed that the area was clean, decontaminated as much as practical, and spray painted. The area is now easily accessible wearing only protective shoe covers and gloves. The inspector had no concerns or additional questions.

5.3 Emergency Preparedness Drill

On August 8, the inspectors monitored one of the periodic emergency preparedness (EP) drills conducted by NMPC. The resident inspectors were assisted by two EP specialists from the NRC Region I office. The drill utilized the Unit 2 simulator control room. The scenario was:

- Increasing offgas radiation levels, the SSS declared an Unusual Event and began a power reduction
- Steam leak causing drywell pressure to increase, the SSS ordered a manual reactor scram
- Not all control rods inserted, resulting in the declaration of an Alert
- Fuel failures resulted due to the scram, causing increased radiation levels
- A main steam line isolation occurred when radiation levels exceeded 3 times normal, but one valve failed to close
- Increasing drywell radiation levels caused the SSS to declare a Site Area Emergency (SAE)
- An unisolable steam leak in the turbine building resulted in the declaration of a General Emergency (GE)

Generally, the inspectors considered that the Nine Mile staff performed well during the drill, and that their actions would be adequate to protect the health and safety of the surrounding public. The licensee's performance was improved since the last NRC observed exercise (October 1994). The major concerns from that exercise were not repeated during this drill. Specific observations include:

- Performance by the control room operators in the simulator was good. Events were quickly identified and properly classified.
- Good command and control was exercised by the emergency director in the emergency operations facility. Periodic briefings were held, notifications

were timely following the SAE and GE declarations, and the proposed protective action recommendation was accurate.

The inspectors attended the licensee's drill critique and determined it was effective. The licensee noted some areas for improvement. Senior station management was present at the critique.

There were 5 NRC open items as a result of previous EP drills and exercises, see section 7.0 of this report for the open item numbers. The inspectors reviewed the corrective actions for each of these items, and observed no repetitive occurrences during this drill. All of the items were closed.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90712)

6.1 Licensee Event Report Review

The below Licensee Event Report (LER) was reviewed for accuracy and compliance with the requirements of technical specifications:

(Closed) LER 50-220/95-04
Operation in Excess of 100 Percent Rated Core Thermal Power due to Feedwater Flow Measurement Errors

This event was accurately discussed in section 4.1 of this report.
LER 50-220/95-04 is closed.

7.0 PREVIOUSLY OPENED ITEMS (92901, 92902, 92903, 92904)

(Closed) URI 50-220/93-80-01
Weak Root Cause Evaluations on Unit 1 SW Related DERs

This item was opened during the 1993 NRC inspection of the NMPC self-assessment of the Unit 1 service water system. The item dealt with a licensee identified weakness in root cause evaluations, as documented on deviation/event reports (DERs).

The inspector reviewed the completed DERs, and found the resolutions acceptable. Further, NMPC changed their DER procedure to specify the use of industry guidance in the root cause evaluation process. This appeared to be effective, as determined during the NRC Effectiveness of Licensee Controls in Identifying, Resolving and Preventing Problems (Inspection Procedure 40500) inspection conducted in 1994 (Inspection Report 94-23/27). Based on the inspector's review, this item is closed.

(Closed) URI 50-410/93-80-02
Long Term Corrective Actions for Unit 2 SW System Problems

This item was opened during the 1993 NRC inspection of the NMPC self-audit of the Unit 2 service water system. The issue concerned the long term corrective actions to address the degradation of the Unit 2 SW system. The degradation was affecting the flow to, and heat removal capacity of, the heat exchangers. Following their audit, NMPC established a team to develop a long term performance enhancement plan. The team completed its initial study and presented its findings to the NRC Region I staff in January 1994, they concluded that the following was needed to improve the SW performance:

(1) Continue testing of heat exchangers as specified in NRC GL 89-13,
(2) Develop a plan to replace small bore pipe to improve flow to unit coolers,
(3) Replace check valves with repetitive problems and remove those that were not needed to meet design requirements,
(4) Install piping and valving to allow for chemical cleaning, and
(5) Revise secondary containment drawdown calculations based on a 60 minute drawdown time.

The inspector reviewed each of these issues and determined the following:

(1) NMPC has conducted two cycles of testing on safety related unit coolers. The testing verified adequate heat removal capability to ensure secondary containment and safety related equipment operability. NMPC used temporary roto-flow meters during testing to provide a more accurate determination of SW flow; vice the previous use of ultrasonic instrumentation. NMPC plans to conduct a third set performance testing during the cooler months of the year such that the largest differential temperature between the lake water and the reactor building exists, to improve the results of the testing.

The inspector reviewed several test procedures and verified that they collected the necessary data (i.e., inlet and outlet air and water temperatures and water flow rate). A technician then used a computer program to calculate how much heat was actually removed during the test and to determine the heat transfer fouling factor. The same program is also used to determine the heat removal capability in the LOCA scenario. To approximate the flow rate during the worst case scenario, NMPC multiplies the actual flow by a factor which takes into account the fouled piping.

The inspector reviewed the calculations and determined that the calculated flow for the worst case scenario was acceptable based on the design service water temperature, air temperature, and the conservative assumptions used during the calculations. The assumptions include a very low lake level, a failure of dams on the St. Lawrence Seaway, and a high discharge canal level due to a discharge pipe tunnel failure.

(2) The inspector reviewed the modification that installed larger pipe in several unit cooler supply and return lines. This was to increase the flow to coolers that had poor hydraulic characteristics, as identified during unit cooler testing and initial flow balancing and design calculations. The inspector reviewed several calculations, and performed independent calculations to verify the appropriateness of methods used.

The inspector determined that NMPC identified the areas of most concern in the hydraulic performance of the system and corrected these areas during the modification. The inspector found that post-modification calculations verified that system flow characteristics would not be adversely affected and that individual unit cooler flows would be improved.

(3) The inspector also reviewed several simple design changes that removed, replaced, or relocated several check valves in the system. The changes addressed several problems that arose during inservice testing of check valves and should make the testing easier to conduct.

(4) During the outage, NMPC installed numerous normally-open isolation valves and test connections that will be used during chemical cleaning of the system during the next refueling outage. Chemical cleaning would remove a large percentage of the internal silting corrosion layer in the piping. If this is successful, NMPC hopes to maintain the internal condition of the piping using routine biocide and chemical treating.

(5) NMPC completed calculations and analysis to revise the secondary containment drawdown time for heat removal considerations from the original 6 minutes to 60 minutes. The assumption for the primary containment heat load was increased by 5% to account for the power uprate. These changes reduced the number of unit coolers that were required to be operable for specific safety related equipment and allowed the heat removal capacity of the secondary containment unit coolers to be reduced.

Overall, the inspector found that NMPC has taken steps to improve the performance of the system by addressing hydraulic choke points. In addition, they have initiated a plan for chemical cleaning of the system during the next refueling outage. Further, the calculation base for the system appeared to be well developed and managed by engineering. NMPC implemented and plans to continue appropriate unit cooler testing to ensure heat removal capability in the worst case LOCA scenario. The knowledge and experience of the system and design engineering staff was a strength. Further, NMPC had completed analysis that indicated that the secondary containment could be maintained at a vacuum to prevent ground level releases in the worst case LOCA accident scenario. Based on these findings the inspector considered this unresolved item closed.

<u>(Closed) URI 50-220/94-21-01</u>
<u>Loss of Configuration Control - Unit 1</u>

The item was opened to document that an NRC inspector identified, during a tour of the Unit 1 control room, that one of the shutdown cooling system temperature control valves was not fully closed, as required. The control room operators and senior operators had just completed their control board walkdowns as part of the shift turnover process. Further review by NMPC revealed at least three other valves to be out of position.

NMPC performed a prompt and thorough investigation and root cause analysis of the mispositioning events, and similar events dating back to 1992. An individual root cause evaluation was conducted for each of event; in addition, they collectively evaluated the adverse trend of the performance errors. NMPC determined that the primary cause for these events has been over-confidence and self-imposed schedular pressure. An independent review by the inspector confirmed the root cause evaluations.

NMPC corrective actions include increased communication between supervisors and workers regarding component mispositioning, tracking of all mispositioning events, and the addressing of the human behavioral performance factors that contribute to mispositioning events. The safety significance of the misposition events was low for the operating condition at the time. None of the valve mispositions affected system operability or violated technical specifications. The corrective actions were prompt, adequate and acceptable. The inspector had no additional questions and this item is closed.

(Closed) URI 50-220/93-12-02 & 50-410/93-12-02
Incomplete and Untimely Notification of the NRC

(Closed) IFI 50-220/94-15-01 & 50-410/94-17-01
Emergency Equipment in the ERFs not in Calibration

(Closed) IFI 50-220/94-15-02 & 50-410/94-17-02
EP Training Weaknesses

(Closed) IFI 50-220/94-21-02 & 50-410/94-23-02
Incorrect Dose Projection Calculation at the EOF

(Closed) IFI 50-220/94-21-03 & 50-410/94-23-03
Weaknesses Identified During EP Exercise

The five above open items are all related to emergency preparedness and were closed based on NRC inspection of the EP drill conducted on August 8, 1995. See section 5.2 of this report for details of the inspectors review.

8.0 MANAGEMENT MEETINGS

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. Based on the NRC Region I review of this report, and discussions held with Niagara Mohawk Power Corporation representatives, it was determined that this report does not contain safeguards or proprietary information.