U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/96-07 50-410/96-07
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:	June 2, - July 27, 1996
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/96-07 & 50-410/96-07
June 2, - July 27, 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; it also includes the results of inspections conducted by regional inspectors in the areas of radiological environmental monitoring and meteorological monitoring, and emergency preparedness. The report also contains a review of the NRC Integrated Performance Assessment Process (IPAP) team inspection report. During the IPAP report review, the inspectors identified violations, unresolved items, and inspection followup items, a summary of which is provided in Attachment A to this report.

PLANT OPERATIONS

- The Unit 1 operators acted appropriately and completed actions in accordance with procedures during the June 6, 1996, feedwater heater level transient. The root cause in the deviation/event report (DER) was accurate, and appropriately supported. NMPC's review to identify potential damage was good, and included structural, fuel, and core shroud analyses.

- During the review of an October 1994 Unit 2 LER, the inspectors determined that there were several missed opportunities for the shift management to identify the correct technical specification (TS) action statement when authorizing concurrent work on multiple hydraulic control unit accumulators. In addition, the work control/planning organization could have aided the operations staff by including the potential plant impact as part of the work package. Nonetheless, once identified, the shift crew took prompt action to ensure the plant was in compliance with the TS. This was identified as a non-cited violation.

MAINTENANCE

- In general, maintenance and surveillance work was conducted professionally, with the necessary procedures at the work site, and with the appropriate focus on safety. As necessary, the proper radiation protection work practices were implemented.

- The Unit 1 operations personnel performed well on all aspects of a routine emergency diesel generator surveillance, accomplished the evolution without incident, and appeared to understand the scope of the surveillance. Communications between the operators in the turbine building and the control room were adequate.

- As a result of corrective actions associated with earlier LERs, NMPC discovered additional surveillances that had not been performed as required. Unit 1 failed to calibrate one of the instruments for the containment leakage detection system during the last two refueling outages; and Unit 2 did not test several valves in the reactor core

isolation cooling system prior to reactor system pressure exceeding 150 psig. The root causes were different, and each was identified as a non-cited violation.

- Unit 2 maintenance technicians performed receipt inspections of new fuel appropriately and in accordance with the procedure. Storage and handling activities associated with the shipping crates and the fuel assemblies on the refuel floor were verified to be in accordance with licensing conditions.

ENGINEERING

- The check valves for the service water system to the unit cooler in the Unit 2 high pressure core spray (HPCS) switchgear room failed the forward and reverse flow tests during a routine surveillance, resulting in the HPCS system being inoperable longer than expected. The inspectors noted that the licensee's past corrective actions to address this issue have not been fully effective. Additional management attention to this issue is warranted.

- A Unit 1 LER identified that the TS limit for the power to flow ratio was exceeded for about 5.5 hours due to the reactor recirculation flow instruments being recalibrated using a new methodology. The new method resulted in a indicated flow reading higher than actual flow if the transmitter was isolated. After the last refueling outage, the unit restarted with one recirculation loop isolated. The cause of the event was an inadequate understanding of the new method and the potential impact on plant operations. This was identified as a non-cited violation.

PLANT SUPPORT

- NMPC continued to implement an effective overall radiological environmental monitoring program and meteorological monitoring program including management controls, quality assurance audits, and quality assurance of analytical measurements. The offsite dose calculation manual was properly implemented. Audits were effective in assessing program strengths and weaknesses.

- A review of revisions to the emergency plan and implementing procedures determined that the revisions did not reduce the effectiveness of the emergency plan and were acceptable.

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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 June 6, power was reduced to 80% to repair the #12 feedwater heater string; power was returned to 100% on June 11. On July 19, power was reduced to 45% to allow cleaning of the north condenser water box. On July 21, the #13 shaft driven feedwater pump would not engage, limiting reactor power to 45% to the end of the period.

Unit 2

Unit 2 maintained essentially full power throughout the period. On June 15, power was reduced to 50% to allow for a shift of feedwater pumps, power was returned to 100% on June 16. On July 19, power was reduced to 78% for a control rod pattern adjustment, full power was restored on June 20.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC resident inspectors conducted inspection activities during normal, backshift, and weekend hours. There was one specialist inspection conducted during this period in the area of radiological environmental monitoring and meteorological monitoring; also, an in-office review was performed regarding changes to the emergency plan and the associated procedures. The results of the inspection and the review are contained in this report.

During this period, the resident inspectors reviewed the report of the NRC Integrated Performance Assessment Process (IPAP) team inspection conducted from March 4 through 22, 1996 (NRC Inspection Report 50-220/96-201 and 50-410/96-201). By charter, the NRR IPAP team inspections do not evaluate their findings with respect to enforcement; therefore, the inspectors reviewed the IPAP report to identify violations, unresolved items, and inspection follow items. Some items identified by the IPAP team had been previously identified or addressed in earlier NRC inspection reports. A summary of the issues identified is provided in Attachment A to this report.

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, operations were conducted professionally and with the proper focus on safety; specific events and noteworthy observations are detailed in the sections below.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Unit 1 Loss of One String of Feedwater Heating

a. Inspection Scope

The inspector reviewed the details associated with the June 6, 1996, feedwater heater level control transient at Unit 1. The review included the applicable portions of the chief station operator (CSO) and station shift supervisor (SSS) logs for the event, and a discussion of the event with members of the operating crew and Unit 1 plant management. The inspectors walked down areas of the plant effected by the transient. The inspectors also reviewed the deviation/event report (DER) written to address the event, and the applicable portions of the Unit 1 UFSAR and Technical Specifications (TSs).

b. Observations/Findings

At 4:02 a.m. on June 6, 1996, while at 100%, Unit 1 experienced a level transient in feedwater heating string #12. Control room operators reduced power to 98.5%, and attempted to restore water level for feedwater heaters #123 and #122 (third stage heater and second stage heater, respectively, in string 12). Operators noted that the #122 feedwater heater piping had moved, due apparently to water flashing to steam within the system. At 4:40 a.m., operators reduced power below 80% and isolated feedwater heater string #12. Operators acted appropriately and completed necessary actions in accordance with procedures.

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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.

To assess the significance of operating with a loss of a feedwater heater string, the inspectors reviewed the applicable portions of the Unit 1 UFSAR and TS. At Unit 1, the feedwater heaters are part of the flow path for the high pressure coolant injection (HPCI) system. The UFSAR states that HPCI is not an engineering safeguards system nor is it considered in any loss of coolant accidents analyses. However, according to the TS, HPCI ensures adequate core cooling in the event of a small reactor coolant line break. The inspectors verified that only one of the three feedwater heater strings are required for HPCI operability.

Later, on June 6, the inspectors, with Unit 1 personnel, walked down portions of the #12 feedwater heater string, including the heaters and the associated feed and steam piping, to assess the damage. A piping support for extraction steam to feedwater heater #122 was found disengaged from the concrete wall, with some damage to the concrete. Three other pipe supports for feedwater heater #122 were found bent. Other components associated with the feedwater heater were also found damaged.

NMPC determined the root cause to be a failure of the level control valve for feedwater heater #122. To evaluate the effect of the transient, NMPC performed the following: an analysis to verify that system integrity was not structurally comprised; an analysis to verify no adverse affect to the reactor or fuel; and an assessment to verify no affect on the core shroud. The results of the evaluations, as well as the root cause analysis of the event, were described in DER 1-96-1389. The Station Operations Review Committee (SORC) reviewed and approved the proposed repairs and related evaluations associated with the event. Repairs to the system were completed on June 10; feedwater heater string #12 was returned to service and the plant was returned to full power on June 11.

The inspectors considered the root cause described in the DER to be accurate, and appropriately supported by the physical evidence of the valve condition and computer data for the feedwater heater string #12 drain cooler flows.

c. <u>Conclusion</u>

The inspectors found that the Unit 1 operators acted appropriately and completed actions in accordance with procedures during the June 6, 1996, feedwater heater level transient. The root cause described in the DER was accurate, and appropriately supported with physical evidence and computer data. NMPC's review to determine the potential damaged cause by the transient was good, as evidenced by the completion of the structural, fuel and core shroud analysis.

O7 Quality Assurance in Operations (71707)

O7.1 <u>Review of INPO Evaluation</u>

The inspectors reviewed the report from the Institute of Nuclear Power Operations (INPO) evaluation conducted from January 29 through February 9, 1996. The evaluation examined the overall operation of the Nine Mile Point site, and was

performed by peer evaluators from other nuclear facilities. The report identified no issues that the NRC was not already aware of, and no additional followup by the NRC is warranted.

O8 Miscellaneous Operations Issues (90712, 90713, 92700)

O8.1 (Closed) LER 50-410/95-12 and LER 50-410/95-12, Supplement 1: Automatic Actuation of Standby Gas Treatment System Because of Inadequate Corrective Action for Snow Plugging of Filters

On December 11, 1995, with Unit 2 operating at 100% power, the standby gas treatment system (GTS) automatically initiated and the normal reactor building ventilation systems isolated. Heavy snowfall and gusty winds caused snow to accumulate on the inlet filters for the normal reactor building ventilation. The purpose of the inlet filters was to remove dust, dirt, and insects, to protect the ventilation cooling coils. During the winter months, the cooling coils are not in service and the system could be operated without the filters.

The shift operators were aware of the decreasing air flow and dispatched personnel to remove the filters from service. However, before the filters could be removed from service, the reactor building ventilation isolated with a concurrent automatic initiation of GTS, due to a low exhaust air flow. Subsequently, the filters were removed, and ventilation was returned to normal.

Licensee Event Report (LER) 50-410/95-12 was first reviewed in NRC Inspection Report (IR) 50-410/96-01; it identified the root cause as being inadequate corrective actions to previously identified problems. Particularly, NMPC noted that similar ventilation degradations had been experienced in the 1980's, caused by snow plugging of the filters. The LER was not closed during the initial review because the listed corrective actions only addressed preventing the inlet filters from again clogging with snow, not the root cause. Therefore, as discussed in IR 50-410/96-01, the licensee agreed to submit a supplement to the LER that described completely the corrective actions to address all root causes.

To address the root cause of inadequate corrective actions, LER 50-410/95-12, Supplement 1, was issued to provide additional information regarding enhancements that had already been made to the NMPC problem resolution process. The process for problem resolution was contained in procedure NIP-ECA-01, "Deviation Event Reports," and included increased oversight of problem evaluations, assignment of trend codes and more stringent requirements for root cause evaluations. The inspectors considered the corrective actions appropriate to address the root cause.

O8.2 (Closed) LER 50-220/96-04: Reactor Scram Caused by Turbine Trip Due to Feedwater Oscillations

On May 20, 1996, Unit 1 experienced a turbine trip and reactor scram from 100% power. The turbine trip was due to a high reactor vessel water level, caused by a failure of the #13 feedwater flow control valve.

The description of the event in the LER, including the root cause analysis and corrective actions, was consistent with the inspectors' review of the event, as documented in NRC IR 50-220/96-06.

O8.3 (Closed) LER 50-410/94-06: Technical Specification Violation Resulting from a Missed Action Statement Caused by Inadequate Work Practices

a. Inspection Scope

This LER describes an event which happened in October 1994, but the LER had not been reviewed previously due to an administrative oversight. The inspectors reviewed the details of the event and the associated LER, the applicable portions of the CSOs and SSS logs for the event, and discussed the event with Unit 2 plant management. The inspectors also reviewed the applicable portions of the Unit 2 TSs.

b. Observations/Findings

During the work control planning process, Unit 2 scheduled two control rod drive (CRD) hydraulic control unit (HCU) accumulators to be worked the same day. The affected departments (maintenance, work control/planning, and operations) had agreed to work the HCUs sequentially, and had noted this in an attachment to the weekly work schedule. However, the agreed upon schedule was not included in the plant impact section of the individual work packages. Subsequently, on October 24, 1994, with Unit 2 operating at 90% power, shift management allowed two HCU accumulators to be made inoperable without implementing the required TS action statements.

Specifically, per TS 3.1.3.5, when an accumulator is inoperable, the associated control rod is also inoperable. If the control rod is inoperable for reasons other than being immovable due to friction or binding, then per TS 3.1.3.1.b, two options exist:

- insert the control rod and disarm the associated directional control valves; or
- if the control rod is withdrawn, verify it is separated from all other inoperable control rods, and insert the control rod at least one notch using normal drive water pressure.

TS 3.1.3.5, action statement a.2.a, states that with more than one accumulator inoperable, and the associated control rods withdrawn, immediately verify at least one CRD pump operating by inserting at least one control rod at least one notch. If a pump is not running, start a CRD pump within 20 minutes and insert at least one control rod one notch, or place the reactor mode switch in the shutdown position.

When the station shift supervisor (SSS) reviewed and approved the first HCU work package, the SSS and the assistant SSS (ASSS) recognized that the control rod was required to be declared inoperable. When the second HCU work package was

reviewed and approved, the SSS knew that a withdrawn control rod needed to be inserted at least one notch to verify CRD pump operability, but failed to inform the ASSS of the additional requirement due to the second control rod accumulator being inoperable at the same time. The chief shift operator (CSO) questioned the appropriateness of having multiple accumulators out of service; the ASSS reviewed, but misinterpreted, the TSs. The second control rod was declared inoperable ten minutes after the first. The ASSS again reviewed the TSs while logging the above into the SSS log. At this point, he recognized that they had not complied with the requirement for inserting a control rod one notch. Twenty-five minutes after the second control rod was inoperable, a different control rod was inserted one notch; meeting TS requirements.

The root cause was an inadequate review by the SSS and ASSS; contributing causes were poor verbal communications between the SSS and ASSS, and poor work coordination that allowed both HCUs to be worked at the same time. Corrective actions included counseling of all SSSs and ASSSs, emphasis on TS implementation during licensed operator requalification training, and enhancements to the work control process.

The inspectors verified that the LER description of the event was consisted with the sequence of events as documented in the control room logs; the inspectors also discussed the LER with Unit 2 operations management. The failure to take the required actions as detailed in the limiting condition of operation for multiple inoperable CRD HCU accumulators, as described above, is a violation of the Unit 2 Technical Specifications, Section 3.1.3.5.a.2.a. However, because this licensee identified event occurred almost two years ago, and the corrective actions appear to have prevented recurrence, this violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusion

The inspectors noted that there were several chances for the shift management to identify the correct TS action statement; during the initial review of the work packages by the SSS and ASSS, and when questioned by the CSO. In addition, the work control/planning organization could have aided the operators by including the potential plant impact as part of the work package. Nonetheless, once identified, the shift crew took prompt action to ensure the plant was in compliance with the TS. In addition, NMPC management took adequate corrective actions to prevent recurrence.

O8.4 (Closed) Unit 1 Special Report: #11 Suppression Chamber Water Level Monitoring System Inoperable

On July 11, 1996, with Unit 1 at 100% power, NMPC removed the #11 suppression chamber water level (SCWL) monitoring system from service for troubleshooting of an erroneous high level alarm. Technicians recalibrated the transmitter and adjusted the alarm setpoint, and returned the system to operable the same day. The redundant train of SCWL remained operable. NMPC submitted a

special report to the NRC within 14 days, as required by the Unit 1 Technical Specifications (TS) 3.6.11-1, action statement 4.a. The inspectors reviewed the special report, and confirmed that all required information was contained in the report.

II. MAINTENANCE[2]

M1 Conduct of Maintenance

M1.1 General Comments

Using Inspection Procedures 61726 and 62703, the inspectors observed plant maintenance activities and the performance of various surveillance tests. In general, maintenance and surveillance activities were conducted professionally, with the work package and necessary procedures at the work site and in use, and with the appropriate focus on safety. As necessary, the proper radiation protection work practices were implemented. Specific activities and noteworthy observations are detailed in the sections below. The inspectors observed all or portions of the following maintenance and surveillance activities:

- N1-ST-M4 — EDGs/PB 102 and 103 Operability Test
- N1-ISP-083-001 — Drywell Liquid Waste Flow Meters
- N2-MMP-FHP-099 — Receiving, Inspecting, and Storage of New Fuel
- N2-ISP-NMS-W@001 — Unit 2 - APRM Channel Functional Test

M1.2 Unit 1 EDGs and Power Board 102/103 Operability Testing

a. Inspection Scope

On July 22, 1996, the inspectors observed operator performance of surveillance procedure N1-ST-M4, Revision. 24, "EDGs/PB [Emergency Diesel Generators/Power Board] 102 and 103 Operability Test." Specifically, Section 8.3, "Diesel Generator 103 One Hour Performance Run," of the reference procedure was observed.

b. Observations and Findings

The inspectors observed operations staff performing the surveillance locally in the Unit 1 Turbine Building. The operators performed the following evolutions:

- hand-jacking of EDG 103 and integrity check of 20 cylinder test valves
- 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

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[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."

- load run

Communications between the operators in the turbine building and the control room were adequate. The inspectors also observed the markup of the EDG for performance of the hand-jacking evolution, and noted conformance with plant policy concerning independent verification of the markup and subsequent valve restoration. No concerns were identified. Starting of the EDG and subsequent load run were monitored by the inspectors, with no identified concerns.

c. Conclusions

The inspectors noted that operations personnel performed all aspects of the EDG surveillance test well. The inspectors determined that the staff appeared to understand the scope of the surveillance and accomplished the evolution without incident.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Receipt Inspection of Unit 2 New Fuel (60705)

The inspectors observed the inspection of new fuel for the upcoming refueling outage at Unit 2. Technicians completed the inspections in accordance with procedure N2-MMP-FHP-099, Revision 2, "Receiving, Inspection, and Storage of New Fuel." The inspectors verified that the receipt/inspection activities complied with the Unit 2 licensing conditions associated with fuel storage and handling. The inspectors concluded that the new fuel handling activities were appropriately completed.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 50-220/95-03, Supplement 1: Technical Specification Surveillance Tests not Performed at the Required Frequency Because of Cognitive Error

On June 13, 1996, as a result of corrective actions associated with LER 95-03, NMPC discovered an additional instrument and control (I&C) surveillance procedure had not been performed within the frequency required by TSs. Specifically, TS surveillance requirement (TSSR) 4.2.5.b.(1) required performance of an instrument calibration on each containment leakage detection system once each refueling outage. The TS bases discussed three subsystems for containment leak detection: rate of rise leak detection; timer leak detection; and integrated flow rate. These three leak detection systems are independent and utilize separate surveillance procedures for performing functional testing and instrument calibration.

The rate of rise and timer leak detection system instrument functional tests and calibrations were performed during refueling outages 12 and 13 (RFO-12 and RFO-13). The integrated flow rate instrument functional test and calibration was accomplished by surveillance procedure N1-ISP-083-001, "Drywell Liquid Waste Flow Meters". NMPC identified this surveillance had been completed satisfactorily

during quarterly surveillance prior to, and subsequent to, RFO-12 and RFO-13. However, the refueling outage TSSR was not performed during either RFO-12 or RFO-13. Since this was another example of a surveillance test not being performed during the refueling outage as required, NMPC issued Supplement 1 to LER 95-03 on July 13, 1996.

LER 95-03 was originally discussed and closed as part of NRC IR 50-220/95-16. The inspectors reviewed the LER Supplement and determined that it satisfactorily described the event, the root cause evaluation, and corrective actions to prevent similar occurrences in the future. The failure to perform the calibration at the required periodicity is a violation of TSSR 4.2.5.b(1); based on the corrective actions and low safety consequence, this licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.2 <u>(Closed) LER 50-410/96-05: Surveillance Requirement Not Performed Per Technical Specifications Due to Inadequate Work Practices</u>

On April 15, 1996, while Unit 2 was operating at approximately 100% power, control room operators discovered that during the performance of Division 3 service water operability testing, the Division 3 EDG had not been declared inoperable as required by TS. This resulted in the failure to perform TS SR 4.8.1.1, verification of breaker alignment and power availability, within one hour as required by TS 3.8.1.1. The failure to declare the Division 3 EDG inoperable was identified by the control room operators approximately three hours after the beginning of the service water testing, when the ASSS was informed that a check valve failed its reverse flow test. At this time, the ASSS and SSS recognized that the EDG should have been declared inoperable at approximately 12:45 p.m. when the surveillance testing began. The SR was satisfactorily completed at approximately 3:45 p.m..

The root cause of the event, as described in the LER, was inadequate work practice by the ASSS. During the ASSS's review of the service water surveillance test, he identified that the EDG would become inoperable. However, instead of consulting the TS to determine the applicable action statement requirements, he continued his review of the surveillance for other plant impacts. This resulted in the failure of the ASSS to declare the EDG inoperable and subsequent failure to met the TS action statement requirement. NMPC identified two contributing factors: the operator performing the surveillance did not understand management's expectation regarding the procedure step to discuss the plant impact with the SSS and CSO, therefore the discussion was not in the depth intended. Secondly, the surveillance procedure did not direct the performance of the TS required actions for this short duration LCO.

The corrective actions for this event, as described in the LER, included counseling the SSS and ASSS regarding the need to fully read, comprehend and initiate compensatory action for all TS requirements prior to allowing work to commence. Also, clarification was provided to all operators with respect to the requirement to discuss the plant impact statement during the work approval process. Additionally,

NMPC planned to evaluate station procedures to determine which should include steps for completing applicable TS required actions.

The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause, and corrective actions to prevent similar occurrences in the future. Based on the adequate corrective actions and low safety consequence this licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.3 (Closed) LER 50-410/96-07: Technical Specification Violation Due to Inadequate Work Organization/Planning

Unit 2 identified additional historical violations of TS surveillance requirement 4.0.4 as a result of the corrective actions associated with Unit 2 LER 96-02. Specifically, on May 20, 1996, NMPC identified that several valves in the reactor core isolation cooling (RCIC) system were not tested prior to reactor system pressure exceeding 150 psig. TS 3.7.4 requires the RCIC system be operable when reactor steam pressure is greater than 150 psig; TS surveillance 4.7.4.b requires that the RCIC pump develop a minimum flow of 600 gpm when steam pressure at the turbine is 935-1035 psig. Because steam pressure is required to test the RCIC pump, TS 4.0.5 [inservice inspection (ISI) and inservice testing (IST)] allows the test to be performed up to 12 hours after adequate steam pressure is available.

The associated surveillance test procedure (N2-OSP-ICS-Q@002, "RCIC Pump and Valve Operability Test and System Integrity Test and ASME XI Functional Test") also tests several RCIC system valves on the water (discharge) side of the pump. The pump must be running to test the valves; accordingly, the valves also cannot be tested until steam pressure is adequate. However, NMPC identified that three of the valves in the procedure do not need the RCIC system to be in operation. Therefore, because TS 3.7.4 requires the valves to be operable, the surveillance test for those three valves must be completed prior to exceeding 150 psig. NMPC determined that these valves had not been tested within the required time frame of three occasions (April 1, 1989, January 24, 1991, June 17, 1992). NMPC determined the cause to be inadequate work organization and planning, because several surveillance requirements were incorporated into one procedure without accounting for different scheduling criteria.

No immediate corrective actions were required. The actions planned to prevent recurrence included revising the IST program plan to identify which RCIC valves can be delayed for testing, and revising the RCIC surveillance procedure to identify which valves must be tested prior to exceeding 150 psig.

The inspectors noted that this was identified as a result of a previous event, which heightened the awareness to the requirement of TS 4.0.4; and to ensuring that required surveillance are performed at the proper frequency. Based on adequate planned corrective actions and low safety consequence this licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 HPCS Inoperable due to Failed Service Water Surveillance

a. Inspection Scope

On July 8, 1996, check valves in the service water system to the high pressure core spray (HPCS) switchgear unit cooler failed to meet the forward and reverse flow as required by the surveillance test. The inspectors reviewed the operating logs, the associated work packages, related DERs and the engineering evaluation. The inspectors also reviewed the surveillance history of the valves, and had discussions regarding recurring surveillance failures with the system engineer and Unit 2 plant management.

b. Observations/Findings

On July 8, 1996, Unit 2 personnel conducted a surveillance test (N2-OSP-SWP-Q005, "Division 3 Service Water Operability Test") of the service water system associated with the HPCS system. During performance of this procedure, the check valve to the HPCS unit cooler failed to meet the acceptance criteria for both forward and reverse flow. After several attempts to clean the system and repair the valves, the reverse flow portion of the N2-OSP-SWP-Q005 surveillance test was completed satisfactorily. Engineering was able to provide a lower minimum acceptance criteria for forward flow, and the surveillance test was completed satisfactorily on July 12.

The inspectors review of the operating logs, the associated work packages, and the engineering evaluation identified no problems. However, the inspectors noted that each time the quarterly surveillance test has been performed since the beginning of the year, the same valves have caused the HPCS system to become inoperable (January 23-25, April 16-19, and July 8-12). Furthermore, in IR 50-410/95-24, the inspectors documented failures of the same surveillance and that Simple Design Change SC2-0034-94 was ineffective in that it required additional design changes to corrected the recurring surveillance test failures. In Spring 1995, SC2-0034-94 was installed, which replaced the original piston check valves with nozzle check valves. During the evaluation of a failed surveillance completed on October 30, 1995, NMPC recognized that the clearance between the plug and the seat of the new valves was too narrow for the maximum expected mussel size (1/8 inch) to pass through. In February 1996, NMPC changed the internals of these valves to provide a larger clearance. However, this February change was also ineffective as evidenced by the continuing surveillance test failures.

When HPCS was inoperable in April, Unit 2 management informed the resident inspectors that one option being considered was removal of the unit cooler check valves. The inspectors consider the delay in finding a final resolution for the

problem with the unit cooler check valves is causing the HPCS system to be unnecessarily inoperable. When discussing this concern with the Unit 2 Plant Manager, it was brought to the inspector's attention that a DER (DER 2-96-1598) had been initiated on July 8 to document both the current failed surveillance and the repetitive failures.

The inspector reviewed the DER and the attached engineering operability determination checklist. The DER listed the apparent cause as due to fouling and corrosion of small bore piping, some of it due to the treatment for clams in the service water system (Clam-Trol). A contributing cause was the failure to revise the inservice testing (IST) acceptance criteria after the earlier failures. Each time the valves failed the surveillance, an operability determination was completed to accept the values for that specific surveillance, but the IST database was never changed. The corrective actions include the issuance of a design document change (DDC) to change the IST database and the associated surveillance procedure. In addition, engineering will process the safety evaluation to support removal of the check valves from the system; the valves are scheduled to be removed by the end of the year.

c. Conclusion

The inspectors considered the delay in finding a final resolution for the problems associated with the unit cooler check valves was causing the HPCS system to be unnecessarily inoperable. Additional management attention is warranted to ensure future corrective actions are effective.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) LER 50-220/96-03: Power to Flow Technical Specification Violation due to Ineffective Change Management

The inspectors reviewed the LER, which discussed the identification, by Unit 1 management on May 9, 1996, that the TS limit for power to flow ratio (PFR) had been exceeded for about 5.5 hours on April 8-9, 1995. During the last Unit 1 refueling outage, Spring 1995, the recirculation flow instruments were recalibrated using a new methodology because of lessons learned from the reactor recirculation pump runback on February 1, 1995. The new method incorporated parameters that resulted in an indicated reactor coolant flow reading higher than actual flow if the transmitter was isolated or equalized. After the outage, the plant restarted using only 4 of the 5 recirculation loops; the idle loop transmitter was isolated, per the operating procedure. The combination of the new calibration method, and the isolated transmitter resulted in an incorrect indicated flow in the idle loop of two million pounds mass per hour (2E6 lbm/hr) instead of 0 lbm/hr.

About one week after startup, the system engineer identified the problem and the transmitter was unisolated and placed in service, providing an accurate indication of loop flow. Initial evaluation by NMPC, based on a review by engineering and the vendor, determined that the error did not cause the total recirculation flow to be

exceeded, but the affect on the PFR correction factor was uncertain. On May 7, 1996, after additional information became available, a re-evaluation was performed; this evaluation indicated that the PFR had been exceeded. NMPC performed an analysis of the event and verified that no fuel limits had been exceeded, and therefore, no cladding or fuel damage occurred. The cause of the event was an inadequate review and understanding of the new calibration methodology and the potential impact on plant operations.

The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause, and corrective actions. Completed and planned corrective actions appear adequate to prevent similar occurrences in the future. However, exceeding the PFR is a violation of TS 3.1.7.d, "Power Flow Relationship During Operation". This licensee identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 <u>Implementation of the Radiological Environmental Monitoring Program (84750)</u>

a. <u>Inspection Scope</u>

The inspectors observed and assessed the licensee's capability to implement the radiological environmental monitoring program (REMP). The inspectors reviewed the REMP procedure manual, visited selected sampling locations to confirm that samples were being obtained from the locations specified in the Offsite Dose Calculation Manual (ODCM), witnessed licensee and contractor personnel exchange air filters and charcoal canisters, examined the air samplers to determine operability and calibration status, and reviewed the results of the Land Use Census. The above areas were inspected against specific TS requirements Sections 3/4.6.20, 3/4.6.21, 3/4.6.22 for Unit 1 and Sections 3/4.12.1, 3/4.12.2, and 3/4.12.3 for Unit 2, the ODCM, and the UFSAR.

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

The environmental protection group, part of the Licensing/Environmental Department at Nine Mile Point, has the responsibility to implement the REMP in cooperation with the J. A. FitzPatrick Radiological Environmental Services Department. Environmental samples were collected by licensee and contractor personnel (Ecological Analysts Science and Technology) and were analyzed at the FitzPatrick Environmental Laboratory (JAFEL).

The sampling stations included air samplers for airborne iodines and particulates, a composite water sampling station (control station), a milk farm, vegetation locations, and several thermoluminescent dosimeter (TLD) stations for measurement of direct ambient radiation. The inspectors witnessed the weekly exchange of

charcoal cartridges and air particulate filters at selected sampling stations. All observed air sampling equipment was operational and calibrated at the time of the inspection. The TLDs were placed at the designated locations as specified in the ODCM. Milk and vegetation samples were obtained from the locations specified in the ODCM. Sample collection was performed according to the appropriate procedures.

The REMP procedures contained all the guidance necessary to collect and prepare environmental sample media. The procedures included air, milk, water sampling methods, dry gas meter calibration calculations for the air samplers, and a method for conducting the Land Use Census. The procedures were of good technical content, concise, and provided the required direction and guidance for implementing an effective REMP.

c. Conclusions

Based on the above review, direct observations, discussions with personnel, and examination of procedures, the inspectors determined that the licensee continued to effectively implement the REMP in accordance with the TS, ODCM, and UFSAR commitments.

R1.2 Meteorological Monitoring Program (84750)

a. Inspection Scope

The inspectors observed and evaluated the licensee's meteorological monitoring program (MMP) to determine whether the instruments and equipment were operable, calibrated, and maintained. The MMP was inspected against TS requirements Section 3/4.7.3 for Unit 2, Section 2.3 of the UFSAR, and Regulatory Guide 1.23.

b. Observations and Findings

The Meteorological Services group continued to have oversight for the MMP; and the I&C department continued to maintain all sensors at the main, backup, and inland towers for the Nine Mile Point/FitzPatrick site and perform calibrations in accordance with Unit 2 TS requirements. The calibration procedures were available and implemented for wind speed, wind direction, temperature sensors, and other related components. The inspectors reviewed the most recent semi-annual calibration results for the above parameters and noted that the calibrations were adequately performed in accordance with the appropriate I&C procedures. All reviewed calibration results were within the licensee's acceptance criteria. The FitzPatrick I&C department calibrated the strip chart recorders in accordance with the licensee's calibration schedule. The results were within the licensee's established acceptance criteria.

The inspectors observed the sensors and the associated outputs in the computer building, as well as the outputs in the Nine Mile control room and Technical Support

Center. Accurate meteorological data were available at each location using digital display from the system computer and analog strip chart recorders.

c. Conclusion

Based on the above review, direct observations, discussions with personnel, and examination of procedures and records for calibration of equipment, the inspectors determined that the licensee continued to effectively implement the MMP in accordance with the Unit 2 TS, UFSAR commitments, and Regulatory Guide 1.23.

R6 RP&C Organization and Administration

R6.1 Organization Changes and Responsibilities (84570)

a. Inspection Scope

The inspectors reviewed any organization changes and the responsibilities relative to oversight of the REMP and MMP since the previous inspection conducted in June 1995, to verify the implementation of the TS requirements.

b. Observations and Findings

The inspectors identified changes in the organizations responsible for the REMP and MMP. In October 1995, the Environmental Protection-Radiological; Technical Services Branch was transferred to the Licensing Branch and subsequently renamed the Licensing/Environmental Branch. The Environmental Protection-Meteorological; Technical Services Branch was relocated to the Emergency Preparedness Department and subsequently renamed Meteorological Services. The Environmental Protection Coordinator-Radiological continued to implement the REMP and report to the Supervisor, Environmental Protection, who reports to the Manager, Licensing/Environmental Branch. Meteorological Services continued to have oversight of the MMP. The Meteorological Services Coordinator reports to the Emergency Preparedness Director, who reports to the Manager, Nuclear Training Branch.

c. Conclusion

Based on the above review, the inspectors did not identify any negative impact on the implementation of the REMP and MMP and confirmed that the responsible personnel in these programs essentially remained the same.

R6.2 Annual Environmental Operating Report (84570)

a. Inspection Scope

The inspectors reviewed the Annual Environmental Operating Report to verify the implementation of the TS requirements Section 6.9.1.d. for Unit 1 and Section 6.9.1.7 for Unit 2.

b. Observations and Findings

The inspectors reviewed the Annual Radiological Environmental Operating Report for timely reportability and the results of the routine analysis of REMP samples and quality assurance results. The Annual Radiological Environmental Operating Report for 1995 provided a comprehensive summary of the analytical results of the REMP around the Nine Mile Point site and met TS reporting requirements. No obvious omissions, anomalous data or trends were identified.

c. Conclusion

Based on the above review, the inspectors determined that the licensee maintained good management control to implement the TS requirements with respect to the Annual Radiological Environmental Operating Report.

R7 Quality Assurance in RP&C Activities

R7.1 Quality Assurance Audit Reports (84750)

a. Inspection Scope

The inspectors reviewed the Quality Assurance (QA) audit report against criteria contained in TS requirements, Section 6.5.3.8.i for both units.

b. Observations and Findings

The nuclear QA audit 95019, "Environmental Protection/REMP and Radioactive Effluents," was performed December 4-8, 1995, and included an assessment of the REMP and MMP. The audit was conducted by the nuclear QA audit group and technical specialists. The scope and technical depth of the audit were good and effectively assessed the programs for strengths and weaknesses. The audit scope also included an assessment at the JAFEL. Few findings and recommendations were identified. The responsible departments responded to these findings and recommendations in a timely manner.

c. Conclusions

Based on the above review, the inspectors determined that the licensee conducted an audit of sufficient technical scope and depth to adequately assess the quality of the REMP and MMP, as required by the regulatory requirements.

R7.2 Quality Assurance of Analytical Measurements (84750)

a. Inspection Scope

The inspectors reviewed the licensee's QA program for analytical measurements of radiological environmental samples including the Interlaboratory Comparison Program (EPA Cross-check Program) required by the TS and ODCM.

b. Observations and Findings

The quality control (QC) program for analysis of environmental samples was the responsibility of the FitzPatrick Radiological and Environmental Services (RES) Supervisor at the JAFEL, located in Fulton, N.Y. The laboratory maintained internal QA programs including environmental split samples, spike samples, and blind samples. Control charts for the gamma spectroscopy counter, liquid scintillation counter, and low background counters were well maintained and calibrations were performed as scheduled. QA samples were analyzed according to the schedule.

The laboratory supplied reports of QC results to the Nine Mile Environmental Protection Coordinator for data review and analysis. When discrepancies were found, the Coordinator consulted with the RES Supervisor. Reasons for the discrepancies were investigated and resolved. The inspectors reviewed the JAFEL Quality Assurance Reports for 1994 and 1995 which contained the results of the QA programs. All reviewed results were in agreement.

The laboratory participated in the EPA cross-check Program. The inspectors reviewed the cross-check results for 1995 and noted that results were within the EPA's acceptance criteria. In 1996, the licensee started to use a vendor laboratory (Analytics, Inc.) to continue the interlaboratory comparison program since the EPA stopped providing this service after December 1995. The inspectors reviewed the cross-check results for the first quarter 1996, and noted that the results were within the established acceptance criteria. The inspectors also determined that the program is equivalent to the EPA cross-check Program. JAFEL plans to use Environmental Management Laboratory (EML) to supplement the Analytics Program. This program is expected to be implemented in September 1996.

Since JAFEL also obtained calibration standards from Analytics Inc., the inspectors questioned if the samples provided for the intercomparison program are independent from the calibration standards. Review of the Analytics Inc. program revealed that independence was assured since Analytics Inc. established two separate and independent programs, one for the calibration standards and the other for the intercomparison program.

The inspectors observed a chemistry technician prepare routine environmental milk samples for counting. The technician followed the procedure and used good laboratory practices. The inspectors also reviewed the analytical results for 1996 (January - July) and noted that there were no anomalous results.

c. Conclusion

Based on the above reviews and discussions, the inspectors determined that the licensee continued to implement a good quality assurance program in accordance with regulatory requirements.

P3 EP Procedures and Documentation

P3.1 In-Office Review of Changes to the E-Plan (82701)

A emergency preparedness specialist inspector conducted an in-office review of revisions to the emergency plan and implementing procedures (EPIPs) submitted by the licensee. The specific revisions reviewed follows. The inspectors determined that the revisions did not reduce the effectiveness of the emergency plan and were acceptable.

Procedure No.	Title	Revision No.
--	Site Emergency Plan	34
EPIP-EPP-01	Classification of Emergency Conditions at Unit 1	6
EPIP-EPP-02	Classification of Emergency Conditions at Unit 2	6
EPIP-EPP-04	Personnel Injury or Illness	2
EPIP-EPP-05	Station Evacuation	1
EPIP-EPP-07	Downwind Radiological Monitoring	2
EPIP-EPP-08	Off-Site Dose Assessment and Protective Action Recommendation	6
EPIP-EPP-09	Determination of Core Damage Under Accident Conditions	1
EPIP-EPP-10	Security Contingency Event	1
EPIP-EPP-12	Re-Entry Procedure	1
EPIP-EPP-13	Emergency Response Facilities Activation and Operation	5
EPIP-EPP-16	Environmental Monitoring	3
EPIP-EPP-17	Emergency Communications Procedure	1
EPIP-EPP-20	Emergency Notifications	5
EPIP-EPP-22	Damage Control	1
EPIP-EPP-23	Emergency Personnel Action Procedures	5
EPIP-EPP-24	Nuclear Transportation Accidents	1
EPIP-EPP-27	Emergency Public Information Procedure	2
EPIP-EPP-30	Prompt Notification System Problem Response	1

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 resident inspector's final exit meeting occurred on August 30, 1996. NMPC did not dispute any of the inspectors findings or conclusions. The preliminary exit for the radiological environmental monitoring and meteorological monitoring inspection was conducted on July 26, 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.

X3 Management Meeting Summary

X3.1 Regional Drop-In Visit by Executive Vice President

On July 16, 1996, Mr. B. Ralph Sylvia, NMPC Executive Vice President and Chief Nuclear Officer, met with Mr. T. Martin, Regional Administrator, Mr. W. Kane, Deputy Regional Administrator, and Mr. R. Conte, Chief, Reactor Projects Branch No. 5, at the NRC Region I offices in King of Prussia, Pennsylvania. The topics discussed were the status of the "Power Choice Option" for the state of New York, in which power companies would individually compete in an open market for the sale of electricity; and the NMPC response to the NRC Notice of Violation and Proposed Imposition of Civil Penalty (dated June 18, 1996). Mr. Sylvia also provided a copy of the response at that meeting.

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
H. Christensen, Nuclear Security Manager
J. Conway, Plant Manager, Unit 2
K. Dahlberg, General Manager - Projects
A. DeGracia, Work Control/Outage Planning, Unit 1
R. Dean, Engineering Manager, Unit 2
G. Helker, Work Control/Outage Planning, Unit 2
J. Jones, Director, Emergency Preparedness
M. McCormick, Vice President - Nuclear Safety Assessment & Support
L. Pisano, Maintenance Manager, Unit 2
N. Rademacher, Plant Manager, Unit 1
P. Smalley, Radiation Protection Manager, Unit 1
R. Smith, Operations Manager, Unit 2
B. Sylvia, Executive Vice President - Nuclear
K. Sweet, Technical Support Manager, Unit 1
C. Terry, Vice President - Nuclear Engineering
R. Tessier, Nuclear Training Manager
K. Ward, Technical Support Manager, Unit 2
D. Wolniak, Licensing/Environmental Manager
W. Yaeger, Engineering Manager, Unit 1

New York Power Authority - J. A. FitzPatrick

N. Avrakotos, Emergency Planning Manger
J. McCarty, Quality Assessment Supervisor
A. McKeen, Radiological and Environmental Services Manager

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60705:	Preparations for Refueling
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observation
IP 71707:	Plant Operations
IP 82701:	Operational Status of the Emergency Preparedness Program
IP 84750:	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
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 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/96-07-01	VIO	The functions of the ISEG are not described in written procedures.
50-410/96-07-02	VIO	Two examples were identified of inadequate procedures for related to the EDG lube oil and fuel oil duplex strainers.
50-410/96-07-03	VIO	A UFSAR drawing for the core spray system was changed without performing a 50.59 safety evaluation.
50-410/96-07-04	URI	Determine if the temporary change process was used to change the intent of an operability test procedure.
50-410/96-07-05	URI	A procedure included in a PMT package was changed after issuance of the work package, without changing the PMt.
50-410/96-07-06	URI	DERs identified several examples of inadequate restoration of systems after maintenance or testing.
50-220/96-07-07	URI	Configuration control concerns due to DCRs were not in the database.
50-220/96-07-08 50-410/96-07-08	URI	Post-job critique information was not incorporated into the WC Mosse database.
50-220/96-07-09 50-410/96-07-09	URI	Several examples of lubrication program problems.
50-410/96-07-10	URI	The mechanical seal on a feedwater pump was replaced without a procedure.
50-220/96-07-11 50-410/96-07-11	URI	No incoming survey for a radioactive material shipment.
50-220/96-07-12 50-410/96-07-12	IFI	Weaknesses in the DER process.
50-410/96-07-13	IFI	ISEG responsibilities associated with the review of NRC issuances.
50-220/96-07-14 50-410/96-07-14	IFI	Weaknesses in the 50.59 safety evaluation process.
50-410/96-07-15	IFI	Long standing hardware problems uncorrected.
50-220/96-07-16	IFI	Unit 1 is unable to parallel the EDGs with offsite for restoration after a loss of offsite power.
50-220/96-07-17 50-410/96-07-17	IFI	MIC control systems installed as temporary modifications over 4 years ago.
50-220/96-07-18 50-410/96-07-18	IFI	Material conditions in several areas of the plant were poor.
50-220/96-07-19 50-410/96-07-19	IFI	Weaknesses in the Emergency Preparedness program.

CLOSED

NONE

UPDATED

NONE

LIST OF ACRONYMS USED

ALARA	As Low As Reasonably Achievable
APRM	Average Power Range Monitor
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CFR	Code of Federal Regulations
CGID	Commercial Grade Item Dedication
cps	counts per second
CRD	Control Rod Drive
DER	Deviation/Event Report
DLA	Dynamic Learning Activities
DOT	Department of Transportation
dp	differential pressure
EPA	Environmental Protection Agency
FB	Fire Brigade
FCV	Feedwater Control Valve
FFD	Fitness for Duty
FPP	Fire Protection Program
ft^2	square feet
GE	General Electric
GEMS	Gaseous Effluent Monitoring System
GTS	Standby Gas treatment System
I&C	Instrument and Controls
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IR	Inspection Report
IRM	Intermediate Range Monitor
ISEG	Independent Safety Engineering Group
ISI	In-Service Inspection
LCO	Limiting Condition of Operation
LER	Licensee Event Report
LPRM	Local Power Range Monitor
MCPR	Minimum Critical Power Ratio
MMP	Meteorological Monitoring Program
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
ODCM	Offsite Dose Calculation Manual
PIP	Position Indicator Probes
psia	pounds per square inch absolute
psig	pounds per square inch gage
QA	Quality Assurance
RBM	Rod Block Monitor

LIST OF ACRONYMS USED
(continued)

RCA	Radiologically Controlled Area
RCS	Reactor Recirculation System
REMP	Radiological Environmental Monitoring Program
RFO	Refueling Outage
RP	Radiation Protection
RP&C	Radiation Protection and Chemistry
RPM	Radiation Protection Manager
RPS	Reactor Protection System
RRP	Reactor Recirculation Pump
RWP	Radiation Work Permit
SE	Safety Evaluation
SFC	Spent Fuel Pool Cooling
SIL	Service Information Letter
SIT	Special Inspection Team
SORC	Station Operations Review Committee
SRAB	Safety Review and Audit Board
SRM	Source Range Monitor
SRV	Safety Relief Valves
SSS	Station Shift Supervisor
STA	Shift Technical Assistant
TLD	Thermoluminescent Dosimeter
TS	Technical Specification
TSSR	Technical Specification Surveillance Requirement
UFSAR	Update Final Safety Analysis Report
URI	Unresolved Item
VDC	Volts Direct Current
VIO	Violation
WO	Work Order

ATTACHMENT A

RESULTS OF THE REVIEW OF NRC IPAP

IR 50-220/96-201 AND 50-410/96-201:

LIST OF VIOLATIONS,

UNRESOLVED ITEMS, AND INSPECTOR FOLLOWUP ITEMS

The review of the results of the NRC Integrated Performance Assessment Process (IPAP) Inspection Report 50-220/96-201 and 50-410/96-201 identified violations (VIO) and unresolved items (URI). Some items identified by the IPAP were previously identified or addressed earlier inspection reports and are annotated as such. The details are contained in the IPAP inspection report (IR), below is a summary of the issues identified for further review:

1. (IR Section 1.1) The responsibilities of the independent safety engineering group (ISEG) are specified in the Unit 2 TSs. The functions of ISEG are described in the Unit 2 UFSAR, which discusses that the establishment of the ISEG is in response to the requirements of NUREG-0737. However, the team identified that there were no procedures for the implementation of ISEG activities. This is a violation of TS 6.8.1.b, which requires written procedures be established and implemented to cover the activities that implement the requirements of NUREG-0737. **(VIO 50-410/96-07-01)**

2. (IR Section 2.4) At the time of the inspection, a procedure upgrade program was in progress at Unit 2 to address problems identified in operations procedures. The team identify the following discrepancies:

   - The Division I and II EDG turbo lube oil duplex filter was aligned to the "BOTH" position, based on the vendor technical manual guidance; this was in accordance with the procedure (N2-OP-100A, Revision 5, "Standby Diesel Generators"). However, the team identified that the alarm response portion of procedure N2-OP-100A for annunciator "Lube Oil Low Pressure Turbo" directed the operator to swap over to the standby filter. With the filter aligned to "BOTH", there would be no standby filter available; thus, the alarm response procedure action could not be performed.

   - The Division II EDG fuel oil duplex strainer was aligned such that both strainer elements were in service. The operating procedure (N2-OP-100A) stated that operation with the selector lever in the "MID" or "BOTH" position should only be considered if the EDG would otherwise be inoperable. However, the selector lever in the "BOTH" position while the EDG was operable. Furthermore, the valve line-up in the procedure noted that the position of the selector lever should be "as selected."

   These represent a violation of the Unit 2 TS, Section 6.8.1, in that procedures were not adequately established or implemented. In addition, the above are examples of conflicting requirements within procedures and are indicative of an inadequate procedure review process. **(VIO 50-410/96-07-02)**

3. (IR Section 3.3) Unit 1 design change (SC1-0056-91) required a revision to UFSAR Figure X-6 to change the position of the service water system screen wash pump header inter-tie valves from normally open to normally closed and to delete an incorrectly shown valve. No safety evaluation was performed because, in the preliminary evaluation (No. D93-113), the responsible engineer documented that the UFSAR was not affected because descriptions in the UFSAR were not changed. The team ascertained that the engineer incorrectly characterized this as an editorial change

to the UFSAR figure. The preliminary evaluation was not in compliance with licensee's procedure NIP-SEV-01, "Applicability Reviews and Safety Evaluations," which did not allow minor configuration changes to UFSAR figures to be considered as editorial corrections. The failure to complete the safety evaluation as required for changes in the facility as described in the UFSAR is a violation of 10 CFR 50.59. **(VIO 50-220/96-07-03)**

4. (IR Sections 2.1 and 2.2) During a review of DER 1-95-0957, the team noted that temporary changes were made to a Unit 1 procedure (N1-ST-Q1B, Revision 4, "Core Spray Loop 12 Pumps and Valves Operability Test") as a part of modification N1-90-041. This item is unresolved pending further NRC review to determine if the temporary changes altered the intent of the procedure. **(URI 50-220/96-07-04)**

5. (IR Section 2.2) DER 1-95-1945 documented that a procedure for post-maintenance test (PMT) of the reactor building track bay door was revised after the work package was issued, the revised procedure deleted some testing requirements for the door. The operations personnel performing the PMT were not aware of this revision. This is an URI pending an evaluation to determine the adequacy of the PMT performed for the reactor building track bay door, and to evaluate the work control process for appropriate barriers in place to prevent recurrence of similar problems. **(URI 50-220/96-07-05)**

6. (IR Sections 2.3 and 4.2) The review of Unit 2 DERs indicated work control problems involving restoration of systems and components following maintenance or testing. For example: an RHR pump minimum flow valve was inadvertently left shut following a surveillance (DER 2-94-1612); an isolation cooling system steam line drain pot level switch variable leg isolation valve was incorrectly left shut following repacking (DER 2-95-0237); and one train of suppression chamber spray was disabled due to failure to properly restore the correct valve line up following a leakage test (DER 2-95-1854). Furthermore, the team reviewed 87 recent work packages, and noted that mechanical work packages did not include a sign-off step at the end of the package to confirm that configuration control was maintained, nor was restoration clearly documented and signed off in the text. This is an URI to evaluate the issues described in the subject DERs, whether the corrective actions taken to address each DER were appropriate, and to evaluate the adequacy of NMPC's controls for configuration restoration following maintenance or testing. **(URI 50-410/96-07-06)**

7. (IR Section 3.2) DERs 1-95-2051 and 1-95-1075 documented configuration control concerns in electrical drawings, because design change requests (DCRs) initiated several years ago were not entered in the configuration control database. Also, drawings in other disciplines were noted as being affected. This is an URI to determine the significance of the configuration control issues documented in the DERs, to review the timeliness and adequacy of the corrective actions identified in each DER. **(URI 50-220/96-07-07)**

8. (IR Section 4.1) The team identified that the information from post-job critique forms was not consistently entered into the work control database (W C Mosse). This is an

URI to determine the procedural requirements associated with the post-job evaluation and the incorporation of the critique information into the WC MOSSE database. **(URI 50-220/96-07-08 & 50-410/96-07-08)**

9. (IR Sections 2.2 and 4.3) Lubrication program problems continued to occur at both units: DER 1-95-2181 documented an error made in adding oil to Unit 1 CRD pump #12 bearing; DER 2-95-2848 documented several instances of delays in preventive maintenance lubrication of pumps and motors at Unit 2; and DER 1-96-0739 documented that SDC pumps #11 and #13 had the motor bearing oil added to the pump bearing and vice versa. This is an URI to evaluate the adequacy of the lubrication programs; the adequacy of corrective actions to address previously identified lubrication concerns; and if the specific issues have been corrected. **(URI 50-220/96-07-09 & 50-410/96-07-09)**

10. (IR Section 4.5) The mechanical seal replacement for the Unit 2 feedwater pump was performed without a procedure, although the work was done by a specially trained maintenance crew. This is an URI to determine if this practice is allowed by NMPC procedures. **(URI 50-410/96-07-10)**

11. (IR Section 5.2.1) NMPC failed to conduct an incoming survey on a radioactive material shipment. This is an URI to determine if the failure to conduct the survey violates NMPC procedures. **(URI 50-220/96-07-11 & 50-410/96-07-11)**

In addition to the violations and unresolved items noted above, the IPAP report noted several weaknesses. These are listed below with an inspector follow item (IFI) number to facilitate administrative tracking to closure.

12. (IR Sections 1.2, 1.3, 2.2, and 4.2) Weaknesses in the DER process were identified in the areas of trending, root cause analysis, adequacy of corrective actions to prevent recurrence, and root cause analysis training. Also, the implementation of corrective actions associated with self-assessments, ISEG, and QA recommendations was not verified sufficiently to assure that the required actions were effective. For DER 2-95-1850, the root cause was a re-statement of the problem, the corrective actions only narrowly addressed the condition and did not address the cause. **(IFI 50-220/96-07-12 & 50-410/96-07-12)**

13. (IR Section 1.1) The team identified that the ISEG responsibilities of reviewing NRC issuances (generic letters, bulletins, and information notices) was being performed by other groups. Except for issues of high interest, ISEG did not systematically review NRC issuances nor performed technical audits of their implementation by line organizations. **(IFI 50-410/96-07-13)**

14. (IR Section 1.2) The team concluded that weaknesses exist in the safety evaluations completed by the licensee. **(IFI 50-220/96-07-14 & 50-410/96-07-14)**

15. (IR Section 3.2) The team noted long-standing hardware problems at Unit 2, such as the loose parts monitoring system, emergency diesel generator air start system, and

standby gas treatment system. The loose parts monitor issue was previously identified as URI 50-410/95-25-02. (IFI 50-410/96-07-15)

16. (IR Section 2.4) Due to the plant design, Unit 1 cannot perform a parallel transfer of loads from the EDG to the offsite power source. This will remain an IFI pending NRC evaluation of the design adequacy. (IFI 50-220/96-07-16)

17. (IR Section 3.2) The temporary modification, at one of the units, for the microbiologically induced corrosion control system for the service water system was installed four years ago. The temporary modification is still in service. THE NRC needs to evaluate the basis for the extended installation period for the temporary modification and plans to remove or make the modification permanent. (IFI 50-220/96-07-17 & 50-410/96-07-17)

18. (IR Sections 2.2 and 4.3) Material condition discrepancies were identified in the rooms for the Unit 2 EDGs, the Unit 2 chilled water pumps, and the Unit 1 SDC pumps. (IFI 50-220/96-07-18 & 50-410/96-07-18)

19. (IR Sections 5.3.3) Many of the weaknesses in the emergency preparedness program were related to changes made in the EP program some time ago. (IFI 50-220/96-07-19 & 50-410/96-07-19)

20. (IR Section 2.1) LER 95-06 for Unit 2 reported the inadvertent disabling of a residual heat removal (RHR) system suppression chamber spray loop due to mispositioning of a manual block valve. During the time period that the loop was disabled, two mode changes were made in violation of Technical Specification 3.0.4. The LER was reviewed in IR 50-410/95-23, and was identified as a non-cited violation.

21. (IR Section 3.2) The IPAP team noted that DER completion dates for the corrective and preventive actions were revised without justification. This issue was previously identified as URI 50-410/95-25-03.

22. (IR Section 5.3.1) The IPAP team noted continuing incidents where personnel had not adhered to site radiological work control procedures and practices. This issue was previously identified as VIO 50-220/96-06-05, 50-410/96-06-05.

23. (IR Section 5.3.2) The licensee had implemented appropriate corrective actions for weaknesses in the performance of security functions, such as unintentional disclosure of safeguards information in a public document and a visitor entering the protected area without a proper escort. These issues were previously identified as URI 50-220/94-13-03, 50-410/94-15-03 and VIO 50-410/94-18-02.