U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 87-25/87-45

Docket Nos. 50-220/50-410

License Nos. DPR-63/NPF-69

Licensee: Niagara Mohawk Power Corporation
301 Plainfield Road
Syracuse, New York 13212

Facility: Nine Mile Point, Units 1 and 2

Location: Scriba, New York

Dates: December 11, 1987 through February 2, 1988

Inspectors: W.A. Cook, Senior Resident Inspector
C.S. Marschall, Resident Inspector
W.L. Schmidt, Resident Inspector
D.J. Florek, Senior Operations Engineer
A.G. Krasopoulos, Reactor Engineer
T.E. Lumb, Operations Engineer
G.W. Meyer, Project Engineer
D. Persinko, Operations Engineer, NRR

Approved by: Jon R. Johnson 2/19/88
J.R. Johnson, Chief, Reactor Projects Section 2C, DRP — Date

INSPECTION SUMMARY

Areas Inspected: Routine inspection by the resident inspectors of station activities including Unit 1 power operations and Unit 2 power ascension testing, licensee action on previously identified items, plant tours, surveillance, maintenance, safety system walkdowns, physical security, radiation protection, LER review, allegation followup; 10 CFR 21 reports, review of material control concerns; Power Ascension Testing reviews and station battery walkdowns. This inspection involved 403 hours by the inspectors which included 46 hours of backshift inspection coverage and 37 hours of weekend inspection coverage. Backshift inspections were conducted on 12/21-12/24, 12/28-12/31, 1/4-1/8, 1/11-1/15, 1/19-1/22, and 1/25-1/30. Weekend inspections were conducted on 12/20, 12/26, 1/2, 1/18, 1/24 and 1/30.

8803030248 880226
PDR ADOCK 05000220
Q PDR

Results:

(Unit 1) A summary of the December 19 feedwater transient and licensee restart commitments is discussed in section 1.1a. A hot particle event is discussed in section 8.1. An allegation concerning replacement RBCLC heat exchangers is discussed in section 10.1. Problems with material control of commercial grade items is discussed in section 14. A review of the condition of all station batteries is discussed in section 15.

(Unit 2) Two violations were identified regarding improperly calibrated trip setpoints for reactor vessel level and CST level instruments (see section 1.2.f.1 and 1.2.f.2). A licensee identified violation of a TS surveillance requirement to record reactor pressure and temperature is discussed in section 1.2.e. A summary of the January 20 reactor scram and inspector review of licensee restart commitments is discussed in section 1.2.f. Inspector review of the response to a Part 21 reporting violation is discussed in section 2.2.d.

DETAILS

1. Review of Plant Events

1.1 UNIT 1

During this inspection period, a reactor startup was conducted on December 11, 1987. The reactor was shut down later that day due to problems with the turbine turning gear. A unit startup was again conducted December 13, and the generator synchronized with the grid at 6:53 a.m. on December 14, 1987. At 1:00 a.m. on December 17, a unit shutdown was commenced due to a failure of one of the main steam isolation valves to stroke partially closed during routine surveillance testing. Adjustments to the valve operating mechanism were made, and the valve retested satisfactorily. The unit shutdown was secured at 2:30 a.m.. At 6:15 p.m. on December 19, the reactor was manually scrammed from approximately 98 percent power due to feedwater piping vibrations. The unit remained shutdown for the duration of this inspection period.

Inspector review of operational events included:

a. The control room operators manually scrammed the reactor on December 19 after sensing control room floor vibrations from feedwater piping vibrations in the turbine building. Minutes prior to the manual scram, operators were dispatched from the control room to investigate #13 feedwater pump auxiliary systems alarms and feedwater heater level alarms. The operator in the turbine building contacted the control room, reported that the feedwater piping and #13 feedwater pump were vibrating, and recommended tripping the feedwater pump. Control room operators commenced reducing recirculation flow and reactor power; however, vibrations were felt in the control room concurrent with several fire detection system alarms, and the Station Shift Supervisor ordered the reactor scrammed.

   After the scram, feedwater piping vibrations rapidly subsided, and the reactor was stabilized in the Hot Shutdown condition. Preliminary inspection of feedwater piping identified only one leaking flange at the feedwater flow venturi. It was quickly determined that the fire detection system alarms were caused by asbestos dust shaken loose from the feedwater piping insulation and not actual fires. Further investigation by the licensee on December 21 determined that the 13A feedwater control valve had suffered a stem-to-disc separation and had apparently been the cause of the severe feedwater piping vibrations. The licensee discovered that the #13 feedwater pump had a broken impeller blade and a wiped outboard pump bearing. A one-inch by two-inch portion of the impeller blade had broken off and has not been retrieved or located in the feedwater system.

Preliminary discussions held between the inspectors and station management indicated that the licensee was planning only a cursory inspection of the feedwater system piping and supports prior to a unit startup. After further discussions with the NRC staff and the licensee's discovery of through-wall cracks in the #11 feedwater pump suction piping, the licensee decided to thoroughly examine the feedwater piping, supports, control valves and pumps prior to unit startup.

The licensee initiated an Engineering Task Force to coordinate the examination of the feedwater system and to analyze the impact of the transient upon the system. Following discussions between the NRC staff and the licensee on December 23, the licensee committed to provide the following to the NRC staff prior to unit restart: a summary of all feedwater system inspections/ examinations and the repairs made, if applicable; an engineering analysis of the feedwater transient and summary results; and, a loose parts analysis for the broken section of the #13 feedwater pump impeller blade which remains in the feedwater system. The resident inspectors will also review the post-trip review package presented to the SORC per their normal scram event followup.

In addition, a special inspection team was onsite between January 11 and January 14, 1988, to review the licensee's assessment of the December 19 feedwater transient. The results of the special team inspection will be documented in NRC Region I Inspection Report 50-220/88-01.

b. During the first week in January, the licensee discovered that several of the ten-year Inservice Inspection (ISI) Program inspections, the majority of which were weld inspections, had either been missed or inappropriately deferred during the 1986 refueling outage. On January 15, the outage was extended to provide sufficient time to remove the reactor vessel head to permit inspection of the reactor vessel flange bushings.

During discussions with licensee representatives, the inspectors determined that the six-inch diameter reactor vessel head studs had all been replaced during the 1981 refueling outage. However, the licensee either failed to inspect the vessel flange bushings or did not document the inspections as required by Section XI of the ASME Code.

The inspectors concluded that these ISI Program discrepancies were identified as a result of licensee corrective actions for recognized program implementation deficiencies. NRC inspector review of the licensee correction action involving the ISI Program will be performed during followup of a previously identified UNRESOLVED item (50-220/87-21-06).

c. On January 22, the licensee decided to continue the present forced outage and proceed directly into their 1988 refueling outage. The 1988 refueling outage was originally scheduled to commence in early March 1988.

d. On January 20, at 4:40 p.m., a station mechanic working on the reactor building refueling floor sustained an injury to his leg. Initial assessment of the injury indicated the injury was contaminated. Based upon this information, the licensee declared an UNUSUAL EVENT in accordance with their Emergency Response procedures.

The worker was extricated from the scene by the fire brigade and transported to the local Oswego hospital via ambulance. A station radiation protection technician accompanied the injured worker to the hospital. The licensee secured from the UNUSUAL EVENT at 5:25 p.m. after the worker was transported off site.

At the hospital, it was determined that there was no skin contamination, intake of radioactive material or significant radiation exposure. The contamination was confined to a small section of the workers protective clothing. The worker was treated for minor abrasions to the left thigh and released.

1.2 UNIT 2

At the beginning of the inspection period, the unit was in COLD SHUTDOWN for replacement of the feedwater system Grayloc couplings and to complete repairs to a ruptured condensate storage tank. On December 21, a unit startup was conducted and Power Ascension Testing per Test Condition 3 (TC-3) was recommenced. On December 26, condenser vacuum problems forced a power reduction from 65% power. During the power reduction, a turbine trip on low vacuum occurred with a resultant reactor scram from 25% power. The cause of the low vacuum was identified to be broken welds on a piping penetration to the condenser. Another unit startup was conducted on December 30. The unit operated at power through the completion of TC-3 and the majority of TC-5 until a reactor scram from 42% power occurred on January 20 due to a loss of instrument air.

The following significant events were reviewed by the inspectors:

a. On December 11, the licensee notified the NRC that they had been operating the unit at various times since initial criticality in June 1987 with suppression chamber air temperature outside the Design Basis Accident (DBA) analysis. The inspectors determined that earlier this year licensed operators had initiated a Problem Report on a nuisance alarm for suppression chamber air High Temperature. The Engineering staff identified that the DBA analysis assumes that the initial temperature in the suppression

chamber will be a maximum of 90 F. The licensee is having Stone & Webster Engineering Co. review the analysis and assumptions. Until this issue can be resolved, the licensee is maintaining suppression chamber air temperature less than 90 degrees F. The inspectors will review the final resolution of this issue in a subsequent report. This item remains unresolved. UNRESOLVED ITEM (50-410/87-45-05).

b. On December 22, an automatic reactor building isolation and Standby Gas Treatment (SBGT) system actuation occurred while performing a surveillance test on a reactor building ventilation radiation monitor. Technicians were installing a jumper in accordance with the test procedure when the jumper accidentally grounded on the side of the cabinet. The jumper grounding caused a ventilation supply damper control fuse to blow and the damper closed. The damper closing caused a low flow condition which resulted in the automatic isolation and train B SBGT system actuation. The A train of SBGT was in pull-to-lock in accordance with the test procedure.

Jumper grounding during the performance of this surveillance test has been a recurring problem at Unit 2. The resident inspectors are following licensee corrective actions.

c. On December 26, a reactor scram occurred from approximately 25 percent power as a result of a turbine trip on low condenser vacuum. The cause of the low condenser vacuum was determined to be a condenser piping penetration weld failure. Subsequent to the reactor scram, circulating water system problems involving the flow distribution in the cooling tower were identified for repair. As discussed in section 9 of this report, the inspector reviewed the causes and corrective actions documented in the Licensee Event Report (No. 87-81) for this reactor scram and found them acceptable.

d. On December 29, a reactor scram occurred due to personnel error while the reactor was shutdown with all rods fully inserted. The licensee was commencing a reactor startup at the time. While placing the mode switch to STARTUP, in accordance with the Reactor Startup Procedure, the Chief Shift Operator (CSO) inadvertently took the mode switch beyond STARTUP to the RUN position. The reactor mode switch is somewhat difficult to rotate because of the multiple contacts associated with it. With reactor pressure less than 766 psig and the mode switch in RUN all MSIVs closed and a reactor scram occurred, as designed. As discussed in section 9 of this report, the inspector reviewed the causes and corrective actions documented in the Licensee Event Report (No. 87-82) for this reactor scram and found them acceptable.

e. On December 30, while conducting a critical reactor heatup, the licensee determined that they had missed a Technical Specification (TS) surveillance check to verify that the reactor was being operated within the pressure and temperature limits. The TS surveillance check requires that this verification be performed every 30 minutes. The checks were not performed between 8:30 a.m. and 11:45 a.m., however, the licensee was able to verify, using the stripchart recorder printouts, that the unit was operated within the pressure and temperature limits. (reference LER No. 87-83, dated January 28, 1988)

Corrective actions were reviewed by the inspector and determined to be adequate. These actions included a clarification to the governing startup procedure, incorporation of this event into the Operations Department Lessons Learned Program for training of all operators, and supervisor counseling of the operator responsible for this TS violation. No previous violations of this surveillance requirement have occurred. In accordance with the provisions of the Enforcement Policy guidance of 10 CFR 2, Appendix C, no Notice of Violation is being issued for this TS surveillance violation. NO VIOLATION ISSUED (50-410/87-45-01).

f. On January 20, the reactor scrammed from 42% power due to a loss of instrument air. The loss of instrument air caused a loss of feedwater flow to the vessel. The loss of feedwater caused reactor water level to decrease and the reactor scrammed at Level 3. After the scram, vessel level continued to decrease until the High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) systems actuated at Level 2 to restore vessel level. HPCS and RCIC were secured at or before Level 8 was reached. Vessel level continued to increase due to the pressure in the vessel dropping below the discharge head of the operating condensate booster pumps. The level increase was halted after water filled the main steamlines.

An NRC Augmented Inspection Team (AIT) was dispatched to the site to investigate the incident. A Confirmatory Action Letter was also sent to the licensee requiring that permission be received from the Regional Administrator prior to Unit 2 restart. A more detailed description of the events leading to the reactor scram and the vessel overfill event is documented in the AIT report (Inspection Report 50-410/88-01).

As a result of the AIT findings, the resident inspectors were tasked with reviewing the corrective action commitments prior to restart. The following items were reviewed:

1. When the Level 2 HPCS and RCIC initiation signals occurred, not all the remaining Level 2 initiation signals were received. Licensee review of calibration data for the effected vessel level instrumentation identified that

several instruments had been improperly calibrated between the Technical Specification (TS) required trip setpoints and the allowable value. Errors had been made when converting the specified trip setpoints, which are more conservative than the TS trip setpoints, to equivalent detector current output trip settings. The individuals who calculated the detector milliamp outputs performed an incorrect linear interpolation, which resulted in detector trip setpoints less conservative than the TS setpoints.

The licensee reviewed all other vessel level instrumentation setpoints and found no other trip setpoint deficiencies. In summary, four Level 2 and four Level 1 vessel level instruments, which provide containment isolation functions, were found set below the Technical Specification trip setpoints. However, the as-found trip setpoints were not below TS allowable values and therefore did not compromise the accident analyses. This is a violation of Technical Specification 3.3.2. VIOLATION (50-410/87-45-02)

2. During review of the level trip setpoints discussed above, the Unit 2 Instrumentation and Controls Supervisor questioned the Engineering staff on the basis for calculating the trip setpoint for the High Pressure Core Spray (HPCS) suction transfer from the condensate storage tank (CST) to the suppression pool. Technical Specification Table 3.3.3 specifies that the transfer setpoint be 12.5 ft above the bottom of the CST. The location of the level transmitters in the HPCS suction piping complicates the setpoint calculation because of the effects of flow induced headloss in the piping between the tank and the transmitter.

   The inspector determined that the CST level transfer setpoint is established to prevent vortexing in the suction piping and potential vapor binding of the HPCS pump. The difference in the headlosses between maximum and minimum HPCS flow is approximately eight (8) feet of water. As a result, if the trip setpoint of the detector was set at a level equivalent to 12.5 feet based on head loss at maximum HPCS flow, then under minimum flow conditions the actual CST level would be 4.5 feet when the detector reached the trip setpoint.

   The inspector determined from the Engineering staff that, due to an error in the calculations provided by Stone and Webster Engineering Corp., the transfer setpoint used was not equal to 12.5 feet in the tank minus the maximum headlosses. Further, the Engineering staff demonstrated that the calculational errors resulted in the transfer

setpoint being set below the minimum required level of 12.5 feet, but higher than the minimum value to prevent vortexing or vapor binding of the HPCS pump. This is a violation of Technical Specification 3.3.3. VIOLATION (50-410/87-45-03)

The licensee has recalibrated the transfer transmitter trip setpoint based on 12.5 feet in the CST at maximum HPCS flow plus an adjustment factor provided by General Electric Company. The inspector reviewed these calculations and determined them to be satisfactory. In addition, in a letter dated February 1, 1988, the licensee committed to revise Technical Specification 3.3.3 to clarify that the transfer setpoint is calculated based on maximum HPCS flow and that for less than maximum flow conditions the actual CST transfer level will be below 12.5 feet. Corrective actions were determined to be satisfactory.

3. The licensee committed to review the design and to make any needed modifications to the feedwater flow control valve operating circuit, based upon observed system operation during the reactor overfill. The inspectors reviewed the modification package and the preoperational testing records and found them to be satisfactory.

4. The licensee committed to review their Operating and Emergency Operating Procedures for any improvements that would assist operators in dealing with similar reactor overfill or loss of instrument air events in the future. The inspectors reviewed operating procedure changes dealing with loss of instrument air and reactor vessel level control after reactor scrams. Another procedure change addressing reactor vessel overfill and coping with a main steamline overfill event was reviewed. All procedure changes were determined to be adequate.

5. The licensee committed to provide training to the Operations shifts on the event and any pertinent information or modifications resulting from the licensee's review of the systems response. The Operations Superintendent assembled a training package which was presented to the operators by a GE Shift Testing Operator (STO). The material covered was well organized and gave the operators a clear sequence of events. The operators were observed to conscientiously review the event and ask questions and provide feedback to the STO.

On February 1, 1988, the Regional Administrator gave permission for restart of Unit 2. Prior to making his decision, region based specialist and NRC headquarters staff reviewed and found

acceptable, the licensee's engineering analysis of the calculated main steamline stresses resulting from the overfill event. In addition, the resident inspectors completed their review of the items discussed above.

The inspectors verified that the licensee made the appropriate 10 CFR 50.72 notifications via the Emergency Notification System for all of the events discussed above.

2. Followup on Previous Identified Items

2.1 Unit 1

a. (Closed) UNRESOLVED ITEM (50-220/81-15-01): Fire detector not installed per NFPA. The original NRC concern with the installations of the fire detectors was that the detectors in the Control Room and the Auxiliary Control Room might be placed near ventilation diffusers and fans which may limit their effectiveness.

The inspector reviewed the installed detectors and did not identify any unacceptable conditions. The licensee installed an area wide fire detection system in the Control Room and the Relay Room (Auxiliary Control Room) in addition to placing detectors in the individual cabinets. This installation should ensure quick detection of any fires in these areas. This item is resolved.

b. (Closed) UNRESOLVED ITEM (50-220/84-06-02): Seal opening in the stairwell firewall. The NRC raised the concern that a construction opening in the wall of the Southeast stairwell of the Turbine Building could allow smoke and other products of combustion to enter the stairwell in the event of a fire in the area. Smoke in the stairwell would impede personnel egress and hamper firefighting activities.

The licensee implemented repairs to seal this opening. The repairs included fireproofing a structural member that forms a part of this opening such that the opening is sealed by the fireproofing material. The inspector reviewed the installation and repairs and did not identify any unacceptable conditions. This item is resolved.

c. (Closed) UNRESOLVED ITEM (50-220/85-01-03): Security modifications to fire doors. In response to a concern that the installation of security hardware on fire doors may have affected the Underwriter Laboratories (UL) rating of the doors, the licensee contracted UL to perform a survey of all fire doors to verify that the UL rating was still valid.

UL performed the survey and issued a comprehensive report, dated March 21, 1985, identifying various door rating deficiencies. The licensee, using this report as a basis, issued repair requests specifying the type of repair work to be performed on each fire door. The inspector reviewed several fire doors to verify that the doors were properly repaired as required by UL. The inspector did not identify any unacceptable conditions. This item is resolved.

d. (Closed) UNRESOLVED ITEM (50-220/85-01-04): Enhancement of illumination levels provided by emergency lighting. During an inspection to verify the ability to safely shutdown the plant in the event of a fire, the NRC raised the concern that in some areas where operators need to perform shutdown tests the illumination provided by emergency lights was marginal.

The licensee reviewed this concern and performed an evaluation titled "Special Order No. N1-50-001, Test Results Summary NMP-1 Emergency Battery Pack Lighting Level Verification of In-Plant Conditions". This evaluation established the lighting requirements to perform various tasks. Using this evaluation the licensee resurveyed the shutdown areas. To enhance the lighting, the licensee installed an additional 60 emergency lights throughout the plant. The inspector toured plant areas and reviewed the emergency lights. No unacceptable conditions were identified. This item is resolved.

e. (Closed) INSPECTOR FOLLOWUP ITEM (50-220/83-18-03): Computer tie-in for wide range level instrumentation. Inspection Report 50-220/83-18 reviewed the installation of wide range reactor vessel level instrumentation for TMI Action Plan Item II.F.2 and found the installation acceptable except that the computer tie-in had not been completed. Inspection Report 50-220/87-10 reviewed the computer tie-in and found it acceptable with the exception of checking the computer points in the surveillance procedure. The inspector reviewed surveillance procedure N1-ISP-M-036-001, Inadequate Core Cooling Reactor Core Level Indication, Revision 1, which properly checked the computer points as part of the surveillance test. This item is closed.

2.2 <u>Unit 2</u>

a. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/87-08-01) To reduce the noise generated by Rosemont 1153 differential pressure detectors and the potential of unnecessary safety system actuations, due to this noise, the licensee has implemented a modification. This modification involves the installation of a capacitor in the trip unit circuitry for these transmitters. The capacitor modification is designed to reduce the fast time response of the detectors.

The inspectors determined that all of the detectors had been modified; however, post-modification testing identified that those detectors providing input to the Reactor Protection System had response times which were too slow. The capacitors were subsequently removed from the circuit. The licensee expects that a modified Rosemont transmitter will be available in the near future that will correct the noise problems and meet the time response criteria. The inspectors will continue to monitor this issue in subsequent inspection periods.

b. (Closed) VIOLATION (50-410/87-29-01): On August 13, 1987, for approximately two hours, neither loop of shutdown cooling was in operation, and no alternate method of coolant circulation was established. This was contrary to Technical Specifications which require that within one hour, shutdown cooling shall be restored or an alternate circulation method established. The inspector reviewed the response to this violation and found the corrective actions to be adequate. The corrective actions include guidance to the Station Shift Supervisors to take actions required to comply with Technical Specification action statements immediately and to try to correct the failure that caused entry into the action statement, concurrently. The inspector had no further questions. This VIOLATION is closed.

c. (Closed) VIOLATION (50-410/87-29-02) During July and August 1987, oil soaked rags and oil puddles were observed at the base of the Division I and II emergency diesel generators. A Notice of Violation was issued for this violation of the Fire Protection Program. The inspector reviewed the violation response, dated November 6, 1987, and determined that the corrective actions appeared to be adequate to prevent recurrence. This VIOLATION is closed, however, the inspectors will continue to monitor licensee progress in the area of housekeeping.

d. (Closed) VIOLATION (50-410/87-02-01): Failure to meet the reporting requirements of 10 CFR 21 pertaining to a flow switch design deficiency in the Standby Gas Treatment (SBGT) system. As documented in Inspection Report 50-410/87-02, the licensee submitted Licensee Event Report (LER) No. 86-16, on January 6, 1987, identifying a flow switch design deficiency in the SBGT system. Subsequent to the issuance of LER No. 86-16, the licensee determined on January 23, 1987 that the flow switch design deficiency constituted a substantial safety hazard. Upon making this determination, the licensee failed to properly notify the NRC in accordance with 10 CFR 21 and their internal notification procedure NEL-029. The substantial safety hazard determination involving the SBGT system flow switch design was appropriately communicated to the NRC verbally on February 27 and in writing on March 4, 1987. A Notice of Violation was issued on April 2, 1987.

The inspector reviewed the response to this violation, dated May 4, 1987, and verified the corrective actions were adequate. The licensee has revised NEL-029 to ensure that the Senior Vice President (Nuclear) or his designee is promptly informed of substantial safety hazard determinations both verbally and in writing and that the NRC is properly notified of these substantial safety hazard determinations.

In the May 4, 1987 violation response, the licensee stated "that there was no violation of NRC requirements associated with the reporting of information relating to the loss of heating for the Standby Gas Treatment System...in that, 10 CFR 21.21 states that an explicit notification is not required if such (responsible) individual has actual knowledge that the Commission has been adequately informed of such defect or such failure to comply." The NRC staff acknowledges that 10 CFR 21 and NUREG 0302, Revision 1, provide alternatives to licensees for reporting operational events or deficiencies. However, in the event of the SBGT system design deficiency, the NRC staff maintains that the Commission was not adequately informed by LER No. 86-16, in that, the substantial safety hazard created was not described.

In addition, the inspectors identified in another inspection period (reference Inspection Report 50-220/87-03 and 50-410/87-09 section 6.2) that the licensee did not fully satisfy the reporting requirements of 10 CFR 50.73 and 10 CFR 21 for two other events in approximately the same time period. Accordingly, sufficient basis has not been provided for retraction of the Notice of Violation. No further licensee corrective action or inspector followup of this violation is necessary. This VIOLATION is closed.

e. (Closed) UNRESOLVED ITEM (50-410/87-39-02) On October 20, 1987, the licensee discovered that the reactor Mode was changed from SHUTDOWN to STARTUP on October 18 with one of two Technical Specification (TS) required trains of the Standby Liquid Control (SLC) system being inoperable. Division I of SLC had been tested on October 17, and a fuse in the firing circuit for the associated squib valve failed. This failed fuse was replaced with a fuse of a smaller amperage rating than the original fuse, 1/4 vice 2 amps. Because a lower amperage fuse was installed, the licensee declared Division I of SLC inoperable. The licensee concluded that if the SLC system was called upon to actuate, the Division I squib valve may not have fired before the smaller amperage fuse blew.

The inspector determined that the reason for the wrong fuse being installed was two-fold: 1) the General Electric Co. drawing used to identify the replacement fuse had the fuse identification numbers for the 2 amp fuse and 1/4 amp fuses interchanged; and, 2) the individuals replacing the fuse did not properly verify the replacement fuse was the correct rating.

In that Division I of SLC was determined to have been inoperable from October 17 to October 20 and the reactor mode was changed from COLD SHUTDOWN to STARTUP on October 18, 1988, this is a violation of Technical Specifications Limiting Condition for Operation 3.0.4. A Notice of Violation is not being issued for this violation in accordance with the provisions of the Enforcement Policy as stated in 10 CFR 2, Appendix C. This violation was identified by the licensee and prompt notification of the NRC followed. The corrective actions taken, including stressing to site staff the importance of ensuring the proper amperage rating of replacement fuses, should prevent any similar problems. There have been no other events of this type for which corrective actions could have prevented this occurrence. This item is resolved. NO VIOLATION ISSUED (50-410/87-45-04)

f. (Closed) VIOLATION (50-410/87-32-01) A surveillance test of the Standby Gas Treatment (SBGT) System was missed because there was inadequate tracking of SBGT run times. Concurrently, a diesel generator was removed from service, and these actions violated a Technical Specification Limiting Condition for Operation (LCO). Niagara Mohawk letter NMP2L 1095 dated December 4, 1987 documented the corrective actions for this violation, including installation of run time meters, procedure changes for operating and logging both the SBGT System and the Control Building Ventilation System, and a review of surveillance test coverage of the Technical Specifications. The inspector reviewed Procedure N2-OSP-LOG-D@002, GTS and HVC Run Time Log, which had been logged on January 27, 1988 and found it to be acceptable.

In addition, at the Enforcement Conference for this violation, Niagara Mohawk stated that a compilation of Technical Specification interpretations would be issued and controlled and that the interpretations would be reviewed and approved by Licensing and Operations. The inspector reviewed the control room controlled copy of NMP-2 Operations Department Operational Information, Vol. 2 - Technical Specification Interpretations, which contained an index of the interpretations, demonstrated suitable approvals, and included appropriate document controls. Further, the control room copy of the Technical Specifications had been highlighted to indicate whether applicable interpretations existed. Based on the above, this item is closed.

g. (Closed) VIOLATION (50-410/87-32-02): Inadequate corrective action for an NRC identified finding regarding SBGT run time tracking. Niagara Mohawk letter NMP2L 1095 dated December 4, 1987 documented the corrective actions for this violation, including implementation of an upgraded commitment tracking system, periodic review of the commitments by senior management, and weekly meetings with the NRC resident inspectors to review

commitment status. On January 27, 1988 the inspector participated in the weekly NRC resident/NMP-2 management meeting, during which the status of the items on the January 27 listing of Resident Meeting Commitment Open Items was discussed. Based on these corrective actions, this item is closed.

3. Plant Inspection Tours

During this reporting period, the inspectors made tours of the Unit 1 and 2 control rooms and accessible plant areas to monitor station activities and to make an independent assessment of equipment status, radiological conditions, safety and adherence to regulatory requirements. The following were observed:

3.1 Unit 1

During the week of January 18, the inspectors toured the refueling floor and observed preparation for removing the reactor vessel head and refuel bridge work activities. Housekeeping had shown marginal improvement since the previous inspection tour documented in the last routine inspection report. The floor was dirty and many loose articles and hand tools were found laying out unattended. A large pile of bagged radioactive materials and equipment still remained in the Northeast corner of the refuel floor. These observations were discussed with station management, who indicated that corrective action would be taken.

During another plant tour, the inspectors observed a large pile of radioactive and asbestos-contaminated protective clothing located just inside the 277 elevation East access gate to the condenser bay. This observation was discussed with both a radiation protection representative and the station Safety Director. The condition was promptly addressed.

3.2 Unit 2

During a few plant tours, the inspector accompanied onshift auxiliary operators and questioned them on systems status and normal operation. The inspector found the auxiliary operators generally knowledgeable of plant systems and operating status.

No violations were identified.

4. Surveillance Review

The inspectors observed portions of the surveillance test procedures listed below to verify that the test instrumentation was properly calibrated, approved procedures were used, the work was performed by qualified personnel, Limiting Conditions for Operations were met, and the system was correctly restored following the testing.

4.1 Unit 1

As documented in section 1.1.b of this report, the inspectors have been involved in the review of the licensee's Inservice Inspection Program.

4.2 Unit 2

a. On December 31, the inspector observed the performance of the Quarterly Residual Heat Removal (RHR) system B train pump and valve operability and system integrity test, N2-OSP-RHS-Q005. The inspector observed that the test was well coordinated and the operators conducting the test were knowledgeable of the desired system response. The operators identified two procedural problems during the performance of the test, and the inspector verified that the appropriate procedure Temporary Change Notices were processed.

b. On January 13, the inspector observed the performance of the recirculation system End-Of-Core Reactor Pump Trip (EOC-RPT) startup test. The General Electric test engineer and the Station Shift Supervisor (SSS) conducted a satisfactory briefing on the test and discussed any actions expected of the operators if the system did not perform as anticipated. When the signal for the EOC-RPT trip was initiated, both recirculation pumps tripped from the 60 hertz power supply as desired, but did not restart on the 15 hertz low frequency motor-generator set, as expected. The inspector determined that the reason for this occurrence was that a test procedure change had omitted changing the test instrument connection point. This resulted in only tripping the recirculation pumps from fast speed to off and not a downshift to slow speed. Regardless, the licensee obtained sufficient test data for the pump trip.

The inspector determined that subsequent review of the test data by the licensee found the results to be outside the transient design basis analysis for flow coastdown. Because of this, the licensee declared the EOC-RPT trip inoperable and took a penalty in the Maximum Critical Power ratio limit as required by Technical Specification 3.2.3. The licensee plans to reperform this Startup Test.

No violations were identified.

5. Maintenance Review

The inspector observed portions of various safety-related maintenance activities to determine that redundant components were operable, that these activities did not violate the Limiting Conditions for Operation, that required administrative approvals and tagouts were obtained prior to initiating the work, that approved procedures were used or the activity

was within the "skills of the trade", that appropriate radiological controls were implemented, that ignition/fire prevention controls were properly implemented, and that equipment was properly tested prior to returning it to service.

5.1 Unit 1

a. In preparation for the upcoming refueling outage the inspectors held a meeting with the unit outage planning coordinator. The inspector determined that the unit has established a Work Control Center consisting of representatives of all major groups on site involved in outage work activities. The procedures which will be used during the outage for planning/preparing, tracking and testing were discussed. The use of the Work Control Center should result in better coordination and communications during the outage. The inspectors will monitor licensee implementation of this new initiative.

b. N1-MMP-7.2, Overhaul of the Shaft-Driven Feedwater Pump (29-01), Revision 0. On January 15, the inspector observed the reassembly of the #13 shaft-driven feedwater pump, in particular, the outboard shaft bearing and thrust bearing. The inspector noted that the maintenance personnel were knowledgeable of the job being performed, and although the procedure was available for review, it was not referred to by the mechanics. The inspector also noted that the mechanics were careful to prevent damaging the new pump parts and to keep all the components properly segregated. The Mechanical Maintenance Supervisor was observed overseeing the pump reassembly and checking with the mechanics to see if any further assistance could be provided.

c. On January 22, the inspector observed the disassembly of one of the turbine combined reheat valves in preparation for nondestructive examination of the valve internals. The inspector observed satisfactory oversight of the activity by supervisory personnel and radiation protection technicians. The inspector noted that the workers performing the disassembly are a specialized work crew which travels to various NMPC power plants performing this type of valve and turbine work.

No violations were identified.

6. Safety System Operability Verification

On a sample basis, the inspectors directly examined selected safety system trains to verify that the systems were properly aligned in the standby mode. The following systems were examined:

6.1 Unit 1

-- High Pressure Core Spray
-- Residual Heat Removal
-- Standby Gas Treatment

6.2 Unit 2

-- Core Spray
-- Containment Spray
-- Emergency Diesel Generators

No discrepancies were noted.

7. Physical Security Review

The inspector made observations to verify that selected aspects of the station physical security program were in accordance with regulatory requirements, including the physical security plan and approved procedures.

7.1 Unit 1

On December 22, at approximately 6:25 a.m., the inspector discovered a station security guard asleep in a parked vehicle. The guard was assigned the duties of a mobile patrol at the time. The inspector contacted the security shift supervisor, who observed the sleeping guard with the inspector and then awoke the individual. The security supervisor immediately relieved the guard of his duties and obtained a replacement.

Although the inspector verified that there was no violation of the Security Plan, the inspector reviewed the corrective actions taken for this event and determined them to be adequate. Corrective actions taken, in addition to those stated above, included: proper documentation of the event and reporting to the NRC; review of the event and retraining of all members of the guard force; and disciplinary action taken against the guard involved.

8. Radiological Protection Review

The inspector reviewed selected aspects of the licensee's radiological protection program to verify that the stations policies and procedures were in compliance with regulatory requirements.

8.1 Unit 1

On December 22, a contract employee working on the old refueling bridge at Unit 1 was found with contamination on the left leg band of his undergarments. Subsequent investigation by licensee radiation protection technicians indicated the contaminated area was a

hot particle of 0.248 micro-curies Co-60 and the skin exposure was estimated at 7.15 REM. The contamination was initially discovered when the worker was exiting via the Friskall monitor at the end of the day.

During discussions with the Unit Supervisor of Radiation Protection on December 24, the inspector determined that upon identification of this contaminated worker the licensee suspended all work on the Refuel Floor, pending further investigation and development of corrective actions. Some of the corrective actions which have since been developed include: wearing additional layers of protective clothing in areas where hot particles are prevalent; additional whole body frisks prior to existing contaminated areas within the radiation area boundaries; required exiting from the radiation areas through the more sensitive Friskall monitors; and additional training of all site radiation workers to sensitize them to the risks of hot particles.

This event and other recent worker contamination events will be reviewed in detail by region based radiation protection specialists during their next routine site visit.

No violations were identified.

9. Review of Licensee Event Reports (LERs)

The LERs submitted to the NRC were reviewed to determine whether the details were clearly reported, the cause(s) properly identified and the corrective actions were appropriate. The inspectors also determined whether the assessment of potential safety consequences had been properly evaluated, whether generic implications were indicated, whether the event warranted on site follow-up, whether the reporting requirements of 10CFR50.72 were applicable, and whether the requirements of 10CFR50.73 had been properly met. (Note: the dates indicated are the event dates)

9.1 Unit 2

a. The following LERs were reviewed and found to be satisfactory:

- -- 87-49, 8/25/87, SBGT initiations due to system low flow.
- -- 87-51, 8/13/87, Shutdown cooling isolation with TS violation.
- -- 87-52, 9/02/87, TS violation SBGT filter media not sampled.
- -- 87-55, 9/16/87, Partial containment isolation.
- -- 87-57, 9/21/87, Shutdown cooling isolation.
- -- 87-58, 10/01/87, Reactor scram.
- -- 87-59, 9/30/87, Surveillance checks missed.
- -- 87-60, 10/22/87, TS violation due to missed surveillance requirements.
- -- 87-61, 10/01/87, Surveillance requirements missed.

-- 87-64, 10/23/87, Turbine trip and reactor scram due to loss of vacuum because of improper isolation of a feed pump.
-- 87-65, 10/15/87, Failure to maintain one quarter inch of vacuum in the secondary containment.
-- 87-66, 10/17/87, SLC inoperable due to fuse problem.
-- 87-69, 10/23/87, Loss of power to RPS UPS
-- 87-71, 11/12/87, Isolation of RCIC due to bumping a high temperature isolation instrument during testing.
-- 87-77, 12/17/87, ECCS actuation
-- 87-81, 12/26/87, Reactor scram due to loss of condenser vacuum.
-- 87-82, 12/29/87, Reactor scram and ESF actuation due to operator error.
-- 87-83, 12/30/87, Missed heatup surveillance.

b. The following LERs were reviewed and determined to satisfactory, however, the identified corrective actions will be monitored and reviewed in a subsequent inspection period:

-- 87-53, 9/03/87, RWCU isolation due to differential flow signal.
-- 87-54, 9/09/87, MSIV isolation signal due to turbine stop valve testing.
-- 87-56, 9/25/87, GEMS and radiation monitors declared inoperable.
-- 87-63, 10/13/87, RWCU isolation due to differential flow.
-- 87-76, 12/12/87, Floor drain design deficiency.
-- 87-78, 12/20/87 and 12/28/87, SBGT automatic starts.
-- 87-79, 12/22/87, SBGT start due to grounding of jumpers.

No violations were identified.

10. Allegation Followup

During the inspection period, the inspectors conducted interviews and inspections in response to an allegation presented to the NRC. The inspector and licensee actions resulting from this allegation are noted below:

10.1 Unit 1

Allegation No. RI-88-A-001: On January 5, 1988, a region based inspector received an anonymous telephone call alleging concerns about heat exchangers being installed at Unit 1. The alleger stated that a contract to AIT (formerly AMER) was awarded for the manufacturing of these heat exchangers and that AIT was not on the NMPC qualified vendor list. The alleger stated that although Unit 1 had not identified any problems with the heat exchangers, other (unnamed) companies have had problems with the fabrication of these heat exchangers.

The inspector determined that the heat exchangers referred to by the alleger are to be used to replace the three existing Reactor Building Closed Loops Cooling (RBCLC) heat exchangers. The specific modification package for the RBCLC heat exchanger replacement, Modification No. 85-48, was reviewed during an earlier site inspection by region based NRC inspectors, (reference Inspection Report No. 50-220/87-22, section 3). The inspector noted that the heat exchanger vendor was not a qualified supplier. However, the inspector determined that the licensee had implemented adequate quality control oversight of both the manufacturing process and installation of the new heat exchangers. The inspector concluded that the RBCLC heat exchanger modification was adequately planned and being properly executed. No additional problems were identified.

This allegation is closed.

11. Part 21 Report Review

During this inspection report period, the following 10 CFR 21 reports were initiated by the licensee:

11.1 Unit 2

a. On November 24, 1987, the inspector was contacted by the licensee concerning an issue that was determined by the licensee to be reportable under Part 21, but of which the licensee knew the NRC was previously informed by Houston Light and Power Company. The licensee decided not to make a report to the NRC, as allowed by Part 21, but did notify the resident inspectors. The substantial safety hazard is that the air filter bowls for emergency diesel generator starting air distributor motors can become loose due to vibration. If these bowls were to become too loose, starting of the diesels may not occur due to loss of starting air pressure. The inspectors have reviewed the licensee's solution to the filter bowl loosening problem and find it adequate.

b. On December 15, 1987, the licensee reported by telephone a potential safety hazard dealing with the design of the Unit 2 floor drain system. The floor drains for the control room filter train cubicles, the main steam tunnel and the auxiliary service building were found to be interconnected and drain to a common reactor building floor drain sump. The potential hazard exists if a main steam line break occurred in the main steam line tunnel. It is postulated that radioactive steam/water mixture could be released through the connecting drain lines, potentially causing damage to safety related components and posing a hazard to personnel in the control room. The written report, dated December 18, 1987, outlines the corrective action to be taken. The necessary drain system modifications were completed prior to the unit restart and were verified by the

inspector to be completed satisfactorily. The remaining drain line modifications will be reviewed in a subsequent reporting period.

12. Licensee Station Reorganization

On January 7, 1988, the Senior Vice President, Nuclear Generation and members of his staff met with representatives of the NRC Headquarters and Region I staffs in the Region I office to discuss the future licensee station reorganization. The purpose of the station reorganization is seen by the licensee as a means of resolving the current problems encountered with the matrix organization and of clarifying individual responsibilities and accountabilities within the station management organization. In addition, the licensee announced the selection of a new senior manager from outside Niagara Mohawk Power Corporation to head up the new station management organization.

The licensee is transitioning into the new station organization and plans to have it fully implemented by the time Unit 2 is placed in commercial operation (tentatively scheduled for late March 1988). Changes to the Final Safety Analysis Report and the Technical Specifications are being discussed between the licensee and NRR staffs.

13. Startup Test Program Test Results Review

The power ascension test results discussed below were evaluated for the attributes identified in Inspection Report No. 50-410/86-64, Section 2.1. The inspector verified that each of the following tests was reviewed by SORC and accepted by plant management. The inspector's review comments were as noted.

-- SUT-11.3 LPRM Calibration - Test results satisfied test criteria.

-- SUT-12.3 APRMs - Adjusted to read equal to or greater than core thermal power as determined by a heat balance.

-- SUT-19.3 Core Performance - While at 65% rated thermal power with total coreflow of 106.87 MLB/HR, CMFLPD was 0.565, CMAPR was 0.558, MAPRAT was 0.550, and MFCPR was 0.546. These values satisfied the test criteria.

-- SUT-81-3 Penetration Cooling - The temperatures recorded satisfied the test criteria.

The inspector also discussed the current Power Ascension Testing progress and plans with the Power Ascension Manager. The inspector reviewed the detailed plans for Test Condition 5 and the revised testing plans for Test Condition 6. No deficiencies were noted.

No violations were identified.

14. Review of Material Control Concerns

On December 19, 1987, an electrical connector was issued by the Unit 2 warehouse for installation in the C main steamline radiation monitor. During a Quality Assurance (QA) Department surveillance activity, the QA inspector identified that this connector was issued for use without a commercial grade dedication first being performed on the part. As a result, the QA inspector issued a Non-Conformance Report (NCR) and the radiation monitor was declared inoperable until the NCR was resolved.

The inspector subsequently determined through discussions with QA Department representatives that the connector was not used and, therefore, did not affect the operability of the radiation monitor. Further discussions with the Manager of Nuclear QA Operations on January 18 and 19 identified that the initial QA surveillance, which identified the improper issuance of the electrical connector, was intended to followup on a Corrective Action Request (CAR) issued against General Electric Co. (GE) supplied commercial grade items. The CAR requires that the Material Management Department place a hold on all GE items procured as commercial grade by either General Physics or Stone and Webster Engineering Company purchase orders. The Materials Management hold was because of a lack of sufficient documentation to support use of these commercial grade items in safety-related applications. Based upon the apparent lack of proper material control measures by the Materials Management Department, the QA Department issued a Stop Work Order on January 19, 1988, for the issuance of all GE supplied commercial grade items at both Unit 1 and 2.

On January 22, the QA Department identified two additional GE components which were improperly released for use. A pulse height discriminator card was replaced in the C source range monitor and a power supply fuse was replaced in the D main steamline radiation monitor. The inspector subsequently determined that the discriminator card received an in-place Engineering dedication and the fuse was replaced with a verified safety-related fuse.

These additional QA findings and closer scrutiny of the material controls for commercial grade items in the warehouse resulted in the QA Department issuing a second Stop Work Order on February 2, 1988, for all commercial grade items in stock. The inspector determined that the basis for the February 2 Stop Work Order was the apparent lack of adequate identification and segregation of commercial grade items in the warehouses and a need to verify the component dedications.

The inspectors will continue to monitor licensee progress in resolving control of commercial grade items procured for application in safety related systems. UNRESOLVED ITEM (50-410/87-45-06)

15. Review of Battery Conditions

In accordance with Region I Temporary Instruction (TI) 87-07, Storage Battery Adequacy Audit, the inspector reviewed the condition of the electrical storage batteries at Units 1 and 2. The scope of the review was batteries associated with the reactor plant and installed inside of the protected area boundary; therefore, any batteries associated only with security or emergency preparedness purposes were not included.

The inspector measured the air temperature of the battery rooms on January 26, 1988. During the inspection the outside air temperature was approximately 20 degrees F. and had been under 30 degrees for several days. Further, both reactors had been shutdown for at least six days. Accordingly, these conditions represented extreme circumstances regarding maintenance of battery room temperature. As demonstrated below, there were no problems identified and the minimum room temperature was 62 degrees F.

Also, the inspector visually inspected the condition of all such batteries for the following:

-- Adequate ventilation, including provisions for supply and exhaust
-- Battery caps in place with no thermometers installed
-- Absence of piping in the room with the exception of eye wash stations
-- Elimination of combustibles and loose equipment
-- Avoidance of localized heat sources (e.g., heaters, steam pipes)
-- Installed fire detectors
-- Enclosed in a room which is locked or key card restricted

The following batteries were inspected:

Battery	Safety-Related	Location	Temperature (degrees F)
UNIT 1:			
Battery 11 (125 V)	Yes	Turbine Building - 277'	78
Battery 111 (24 V)	Yes	(Same room as battery above)	
Battery 112 (24 V)	Yes	(Same room as battery above)	
Battery 12 (125 V)	Yes	Turbine Building - 277'	76
Battery 121 (24 V)	Yes	(Same room as battery above)	
Battery 122 (24 V)	Yes	(Same room as battery above)	
Auxiliary Batt. (250 V)	No	Turbine Building - 250'	76

UNIT 2:

2BYS-BAT 1A (125 V)	No	Normal Switchgear Bldg - 237'	65
2BYS-BAT 1B (125 V)	No	Normal Switchgear Bldg - 237'	64
2BYS-BAT 1C (125 V)	No	Control Building - 214'	79
2BYS*BAT 2A (125 V)	Yes	Control Building - 261'	70
2BYS*BAT 2B (125 V)	Yes	Control Building - 261'	74
2BYS*BAT 2C (125 V)	Yes	Control Building - 261'	70
2BWS-BAT 3A (24 V)	No	Control Building - 214'	74
2BWS-BAT 3C (24 V)	No	(Same room as battery above)	
2BWS-BAT 3B (24 V)	No	Control Building - 214'	77
2BWS-BAT 3D (24 V)	No	(Same room as battery above)	
2FPW-BAT 1A (24 V)	No	Screen Well - 261'	62
2FPW-BAT 1B (24 V)	No	(Same room as battery above)	

The inspector found the following:

-- The condition of all batteries was acceptable. In particular, the Unit 2 batteries were in excellent condition, and the Unit 2 Battery Rooms were uniformly clean and well maintained.
-- One small space heater was ceiling mounted in both Battery Room 11 and Battery Room 12 in Unit 1, approximately five feet from the nearest battery. These heaters appeared to present practically no risk of any significant local distortions of room temperature, and the inspector concluded that the heaters were acceptable.
-- One cell was jumpered out in Unit 1 Battery 11 due to its inability to hold a charge. The Electrical Maintenance Supervisor stated that due to gradual deterioration of all cells in this battery, replacement cells had been ordered and would be installed when available.

In addition, the inspector verified the readiness of a sample of battery operated emergency lighting. All were acceptable except one battery light in Unit 1, and a maintenance work request was written to correct this battery.

No violations were identified.

16. Inspection Summary - Assurance of Quality

Licensee evaluation of the Unit 1 feedwater transient was comprehensive, (licensee final report due March 1, 1988). However, the licensee appeared hesitant to conduct a thorough assessment until prompted by the NRC staff. As a result of their corrective actions for identified ISI Program (Unit 1) violations, additional evidence of a poorly implemented ISI Program were identified by the licensee during this inspection period. Licensee assessment of the Unit 2 reactor scram and vessel overfill event was thorough and timely. In addition, the licensee was responsive to the Augmented Inspection Team, sent to the site to investigate the event. The two TS instrument calibration violations identified as a result of the review of this event may indicate inadequate oversight of station contractors responsible for those calibration procedures and supporting calculations. Housekeeping at Unit 1 still requires management attention; efforts, to date, have not been totally effective. Maintenance activities observed were well-executed and adequately supervised. Licensee efforts to minimize and detect hot particle contamination appear to be satisfactory. The Power Ascension Testing Program at Unit 2 continues to be well executed. Licensee efforts to resolve inadequate control of commercial grade items appear to be adequate; however, these problems indicate a need for better oversight of the Materials Control organization.

17. Exit Meetings

At periodic intervals and at the conclusion of the inspection, meetings were held with senior station management to discuss the scope and findings of this inspection. Based on the NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain Safeguards or 10 CFR 2.790 information.