U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 87-24/87-42

Docket No. 50-220/50-410

License No. DPR-63/NPF-69 Category B

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: October 31, 1987 through December 10, 1987

Inspectors: W.A. Cook, Senior Resident Inspector
W.L. Schmidt, Resident Inspector
G.W. Meyer, Project Engineer
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Approved by: Jon R Johnson 1/7/88
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 testing review, safety system walkdowns, LER review, TMI Action Plan items review, scram discharge volume design review, Part 21 review, followup to GL 84-11, and IE Bulletin review. This inspection involved 304 hours by the inspectors which included 42 hours of backshift inspection coverage and 10 hours of weekend inspection coverage. Backshift inspections were conducted on 11/3-11/5, 11/9, 11/10, 11/17-11/20, 11/23, 11/24, 11/26, 11/28, 11/30-12/5, and 12/7-12/10. Weekend inspections were conducted on 11/28 and 12/5.

Results: Two unresolved items were identified during this inspection period. Corrective actions for a licensee identified LSSS violation were not finalized prior to the end of the inspection; therefore, enforcement action is unresolved (see section 1.1.a). Licensee compliance with a June 1983 Confirmatory Order regarding SDV design and testing remains unresolved (see section 8). Review of Generic Letter 84-11 is discussed in section 10. Review of IE Bulletin 87-01 is discussed in section 12. The Unit 2 Condensate Storage Tank rupture is discussed in section 11.

DETAILS

1. Review of Plant Events

1.1 UNIT 1

a. On November 16, during supervisory review of a computer generated core thermal limit evaluation (P-1) performed on November 15, the licensee determined that the Total Peaking Factor (TPF) had been greater than 3.0 (highest recorded value was 3.428) between approximately 5:30 a.m. on November 15 and 1:01 a.m on November 16. Reactor power during this time was approximately 44 percent. TPF greater than 3.0 is a violation of a Technical Specification limiting safety system setting (LSSS). The reactor analyst performing the thermal limit evaluation should have adjusted Average Power Range Neutron Monitors (APRMs) to compensate for this abnormally high TPF.

At the time the LSSS violation occurred, the reactor was in a xenon transient due to a prolonged power reduction and subsequent control rod pattern adjustment. TPF dropped below 3.0 as reactor power was increased and xenon built in. The licensee considers that fuel damage was unlikely due to the relatively low power level at the time. The licensee plans to discuss this event with General Electric Co. nuclear engineers.

The inspector has determined that during routine plant operations, the computer program results for core power and thermal limits are not required to be reviewed by licensed Operations Department personnel to verify compliance with Technical Specification (TS) thermal limits. The responsibility for this detailed review and compliance with TS thermal limits is given to unlicensed, but specially trained technicians in the Reactor Analysts Department. This item remains unresolved pending inspector review of licensee corrective actions to prevent recurrence. UNRESOLVED ITEM (50-220/87-24-01)

b. On November 7, the licensee identified that four of the offsite emergency notification sirens had been out of service. The licensee speculates that the siren power supply breakers tripped open due to electrical transients in the siren monitoring circuits caused by thunderstorms which passed through the area the evening of November 6. Niagara Mohawk and New York State Power Authority (FitzPatrick Nuclear Power Station) have engineers researching a solution to the sensitivity of the siren monitoring circuits to electrical storms.

c. On November 23, during a routine check of the emergency notification siren monitoring system, the licensee determined that for a period of approximately one hour on November 20, seven sirens were out of

service due to a power loss. The power loss was caused by an automobile accident involving one of the power poles which feeds the emergency sirens. Five of the sirens had power restored within an hour and a sixth siren was operable after two hours. The seventh siren remained out of service for approximately 48 hours.

The inspector determined that the delay in identifying that the sirens were inoperable was due to the inability of the licensee to remotely monitor all emergency sirens. The monitoring panels currently in use are located in facilities which are not manned 24 hours per day. The inspector determined that the licensee plans to modify the monitoring system and provide remote monitoring capability at the NMPC Granby District Operations Center, an office manned around-the-clock.

d. At 00:54 a.m. on December 7, a reactor scram occurred due to malfunctioning feedwater control valves. The reactor scram signal was generated by a low reactor water vessel level condition resulting from attempts by the operators to manually override one of the control valves. The inspector determined that operator actions were appropriate in attempting to correct the problems and in response to the reactor scram.

The licensee determined that the causes for the feedwater control valve problems were a drifted gain setting on the feedwater master controller resulting in slow valve response time and blockage in the air supply line to one of the valve actuators. The master controller was recalibrated and the licensee has initiated a modification request to install additional filters on the control valve air supplies. Also, the licensee is evaluating whether internal valve malfunctions occurred.

1.2 <u>UNIT 2</u>

a. During this inspection period, unit power was increased to approximately 65% with 100% core flow. Under these high power and flow conditions, oscillations in reactor power, reactor vessel level, recirculation flow, and recirculation pump motor amperage were observed. Initial review indicated that the oscillations may have been caused by flow instabilities in the recirculation loop riser (vertical section of the loop return line which connects to the jet pump riser manifold). This phenomena was described in NRC Information Notice No. 86-110. Subsequent review by the licensee and General Electric Co. engineers concluded that the oscillations are the result of global nucleate boiling in the core. This type of boiling in the core and observed oscillations is considered by the licensee to be typical of the BWR-5 product line and not considered of any safety consequence.

These oscillations will be monitored by the licensee's startup testing group and will be followed by the NRC inspectors during future planned power ascension testing.

b. On November 4, the licensee declared both the Division I and II batteries inoperable due to corrosion on terminals. The requirement to check for corrosion is included in Technical Specification (TS) 4.8.2.1.c. as an 18 month surveillance. The licensee has experienced corrosion buildup on battery terminals in the recent past and has implemented more frequent surveillance checks. DC power source TS 3.8.2.1 does not have an Action Statement for the condition when both Division I and II batteries are inoperable. Accordingly, the licensee commenced a shutdown at 3:50 a.m. as required by TS 3.0.3. The shutdown was terminated at 4:10 a.m. when both batteries were returned to service after corrective maintenance.

The inspector determined that the corrosion buildup observed has been evaluated by the licensee as not effecting the resistance of the battery connections. The licensee is reviewing solutions to the relatively rapid corrosion buildup problem and is considering a TS change with respect to corrosion on battery terminals and its impact on battery operability.

c. On November 12, the Reactor Core Isolation Cooling (RCIC) System steam line isolated due to a spurious signal from a Residual Heat Removal (RHR) System area high temperature instrument. At the time of the isolation, I&C technicians were conducting testing on the RCIC equipment area high temperature isolation instrument and had this isolation signal bypassed. Due to the close proximity of the RHR and RCIC temperature instrument trip units, while lifting leads on the RCIC trip unit, wiring to the RHR trip unit was disturbed and this caused the isolation signal. The isolation signal was cleared and the steam line unisolated.

d. On November 21, the licensee determined that they were potentially in violation of Technical Specifications (TS) for an inoperable main steam line radiation monitor. On November 20, main steam line radiation monitor Channel D was reading lower than the three other channels and was declared inoperable. A half scram and half main steam line isolation signal were inserted, in accordance with TS, and a recalibration of the radiation monitor was performed. Channel D was subsequently declared operable and the scram and isolation signals were cleared; however, the associated paperwork was not completed to administratively return the radiation monitor to service.

On November 21 after a shift turnover, the oncoming Station Shift Supervisor identified that the radiation monitor was in operation for approximately three hours without the appropriate paperwork closed out. He considered the monitors inoperable for those three hours and that proper compensatory action was not taken in accordance with TS. He also made the appropriate initial notifications, via the ENS, of the potential TS violation.

Subsequent review of this event by licensee supervision determined that there was no TS violation and that this event was not reportable per 10 CFR 50.72 or 50.73. The inspectors concurred with this determination and discussed with licensee management the causes and actions to be taken to preclude similar problems in the future.

d. On November 22, a unit shutdown was conducted to commence a projected four week modification outage. During the current phase of Power Ascension Testing (Test Condition 3), a leak developed on one of four "Grayloc" pipe couplings in the main feedwater header. The licensee determined that the leakage resulted from the inability of this type of pipe fitting to withstand the excessive thermal stresses induced by thermal stratification in the 24 inch feedwater lines. The licensee planned to remove the "Grayloc" couplings and replace them with standard flange-type fittings.

e. At 1:00 p.m. on November 22, chemistry technicians identified that the tritium sampler on the Standby Gas Treatment (SBGT) system effluent monitor was drawing insufficient sample flow. The SBGT system was in operation to purge the drywell in preparation for personnel entry. The licensee determined that at 8:55 a.m. normal sample flow was lost due to swapping of SBGT system trains A to B. The technicians immediately restored normal sample flow and contacted the Station Shift Supervisor (SSS). The SSS determined that the loss of continuous sampling for tritium during containment purging was a potential Technical Specification action statement violation and notified the Headquarters Duty Officer via the ENS.

Subsequent review of this event by licensee supervision determined that this event was not a TS violation and was not reportable per 10 CFR 50.72 or 50.73. The inspectors concurred with this determination and discussed with station management the actions to be taken to clarify the TS purging sample requirements and to ensure proper operation of the tritium sampler during subsequent drywell purges.

f. On November 24, an inadvertant reactor water cleanup (RWCU) system isolation occurred as a result of personnel error. Preparations were being made to work on the RWCU system suction line flow transmitter. The Chief Shift Operator (CSO) supposedly bypassed both divisions of the RWCU high delta flow trip units prior to authorizing the isolation of the transmitter. However, the CSO mistakenly bypassed the Division II reactor core isolation cooling (RCIC) trip unit instead of the Division II RWCU high delta flow trip unit. The RCIC and RWCU trip unit bypass switches are located next to each other.

When the suction line flow transmitter was isolated, the Division II RWCU isolation signal was generated and caused the operating RWCU pump to trip and the system to isolate. All components functioned as designed.

The inspector discussed this event with the CSO involved and determined that he was not careful to ensure that the correct trip unit was bypassed and was distracted by another event in progress. The inspector considers this an isolated event and not indicative of a problem with operator attentiveness.

g. On November 28, the A condensate storage tank (CST) ruptured spilling its entire contents of nonradioactive demineralized water (approximately 300,000 gallons). This event was reviewed in detail and is discussed in section 11 of this report.

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

2. Followup on Previous Identified Items

2.1 Unit 1

a. (Closed) INSPECTION FOLLOWUP ITEM (50-220/86-12-01): Review of licensee action concerning the reporting requirements of 10 CFR 21 and 10 CFR 50.73. This item is closed based upon inspector review of item 50-410/87-02-01 discussed in section 2.2.d below.

2.2 Unit 2

a. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/86-52-01): Independent review of Quality First Program (Q1P) resolution of Quality Assurance (QA) concerns. NMPC responded in a letter dated December 16, 1986 that administrative procedures would be revised to have the Safety Review and Audit Board (SRAB) review the Q1P resolution of QA concerns and to provide periodic updates to the SRAB Chairman concerning the status of the concerns. In addition, periodic meetings are held with NRC resident inspectors and NMPC management to apprise them of ongoing evaluations. The inspector reviewed Quality Assurance Procedure (QAP) 16.70, Quality First Program, which specified the involvement of SRAB, and two SRAB agendas, which included coverage of Q1P. This item is closed.

b. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/86-52-02): Weak administrative control of troubleshooting work activities. NMPC responded in a letter dated December 16, 1986 that administrative procedures had been revised to properly control troubleshooting work activities. The inspector reviewed AP 3.3.2, which included an additional section (3.7) with controls on troubleshooting. Also, the inspector reviewed QA controls on troubleshooting with the Supervisor QE/QC, who stated that troubleshooting is performed on Work Requests (WRs) approved for "troubleshooting only". Once the problem is determined, any repairs must be done on a revised WR which approves the specific repair. The inspector reviewed WR No. 129952, which demonstrated this process. This item is closed.

c. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/86-52-03): QA implementing guidance and continuing training on the same. In discussions with the inspector, the Supervisor QE/QC stated that during the inspection, QA implementing guidance was informal. Subsequently, this implementing guidance was written, reviewed, and approved in the form of Nuclear Quality Assurance Operations (NQAO) Activity Guidelines. There are currently 19 Activity Guidelines, which provide specific detailed guidance on routine QA functions. These Activity Guidelines are part of the training each QA person receives. The inspector reviewed the Activity Guidelines and concluded that they represented a much improved method of providing QA implementing guidance and training. This item is closed.

d. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/86-52-04): Inconsistent hold points between Quality Control (QC) checklists and maintenance procedures. The inspector performed a comparison of hold points between the QC checklist and Maintenance Procedures N2-MMP-30.3, -32.1, -35.1, and -36.1 and found no inconsistencies. The Supervisor QE/QC stated that as maintenance procedures are revised, QC personnel review the changes and modify their checklists at that time. This item is closed.

e. (Closed) INSPECTOR FOLLOWUP ITEM (50-410/86-52-05): Trending of bypassed QC hold points. NMPC responded in a letter dated December 16, 1986 that future instances of bypassed hold points would be corrected and also trended. The Supervisor QE/QC stated that currently any bypassed hold points are documented on a Corrective Action Request (CAR) and corrected. Further, all CARs are trended. The inspector reviewed Quarterly Trend Analysis Report #87-3, which included a detailed breakdown on the areas in which CARs and other QA documents occur. This report included no bypassed hold points, and only three occasions when QC was not notified. The inspector concluded that this corrective action was effective and acceptable. This item is closed.

f. (Closed) VIOLATION (50-410/87-08-02): Failure to follow procedures and alarm response requirements. The licensee responded to this violation by letter dated September 8, 1987. The response recognizes that the instances of failure to follow procedures did occur and outlines several corrective actions. The first actions addressed in the licensee's response were completed when the violations were brought to station management's attention. These actions included the changing of the appropriate operating procedures to give the operators more guidance. The second and third corrective actions addressed in the response were to issue a memorandum on the events to the operators and to make an administrative procedure change to clarify the use of alarm response procedures. These actions were to be completed by November 1, 1987. The inspector found that neither of these actions had been completed as of November 4.

During discussions with licensee management responsible for these actions, it was found that these individuals were not aware of their corrective action responsibilities until after the commitments were to have been met. The Operations Superintendent became aware of his commitment to write the memorandum during his discussions with the inspector on November 4. The Superintendent of Technical Services became aware of his commitment to revise the administrative procedure upon reviewing the violation response on November 2, 1987. The inspectors discussed these observations with licensee station management and determined that these NRC commitments had not been properly tracked because of an administrative oversight. The normal routing of the violation response was circumvented due to delays in getting the response letter signed out and mailed. This is an example of ineffective licensee commitment tracking.

Prior to the conclusion of this inspection period, the inspector reviewed all of the corrective actions identified for this violation and found then to be adequate. Operators have been provided sufficient guidance for when to use their discretion in following safety related systems operating and alarm response procedures. This violation is closed.

The inspector will continue to monitor licensee actions to prevent missing future commitments to the NRC.

g. (Closed) VIOLATION (50-410/87-20-01): On June 8, 1987, the reactor building Truck Bay fire detection system was taken out of service and the compensatory fire watch patrol was not performed in the effected area, as required. The licensee responded to the Notice of Violation for this event by letter dated September 29, 1987. The inspector considers the corrective actions documented in this response to have adequately addressed the root causes for this violation. The inspector has verified that the licensee has provided fire protection supervision with improved methods for tracking fire detection and suppression systems which are removed from service, and that training of firewatch personnel was adequate. This violation is closed.

h. (Closed) VIOLATION (50-410/87-25-01): Failure to identify, record and disposition a pipe weld radiograph containing a rejectable zone of incomplete fusion. The response to this violation, dated October 12, 1987, was reviewed and determined to be acceptable, as previously documented in Combined Inspection Report 50-220/87-21 and 50-410/87-39, Section 6. The inspector had no further questions or concerns. This violation is closed.

i. (Closed) VIOLATION (50-410-/87-37-03): On September 1, 1987, the licensee was operating the reactor at 40% power with thirteen high/low pressure interface valves energized, in violation of 10 CRF 50, Appendix R, Section III.L.7. The inspector reviewed the licensee response to this violation dated November 24, 1987. The inspector determined that the licensee has taken appropriate corrective action to prevent recurrence. Procedural revisions have been made to ensure proper deenergization and tagging of the valves and operators have been provided a clear definition of when the valves are to be removed from service. This violation 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

a. During several different tours of the EDG rooms, the inspectors noted fuel oil puddled at the base of the EDGs. Station management was informed of these observations and they indicated that the oil would be promptly removed and periodically cleaned up. The inspectors will continue to monitor licensee efforts to keep the EDG platforms clean and oil free.

b. On December 8, the inspector toured the refuel floor while the licensee was rigging the new refuel bridge platform up to the refuel floor. The inspector noted no discrepancies with the rigging operations, however, the general housekeeping on the refuel floor was observed to be poor. Dirt and debris was scattered on the floor, lubricants, sealants and cleaning agents were adrift, anticontamination clothing was not properly disposed of, tools were not properly stored and numerous pieces of bagged contaminated tools and equipment were piled or otherwise being stored on the refuel floor. The inspector did note that the dryer/moisture separator and spent fuel pits were covered to limit the amount of dirt and debris introduced.

After completing his tour of the refuel floor, the inspector discussed his observations with the Unit Superintendent and determined that the Unit Superintendent was aware of its condition. The Unit Superintendent indicated that the refuel floor would be cleaned up as part of the contract agreement made with the contractor responsible for the new refuel bridge assembly. In addition, much of the contaminated materials stored on the refuel floor would be removed with the waste shipments generated by the disassembly of the old refuel bridge.

3.2 Unit 2

No discrepancies were noted this inspection period.

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

N1-IMP-C-FWC-7, "Replacement/Repair of Fisher 3570 Valve Positioners for Feedwater Valves 11, 12, and 13", revision 1, effective May 1986, performed on the 12A and 12B feedwater control valves on December 8, 1987.

4.2 Unit 2

N2-OSP-EGS-R002, "Operating Cycle Diesel Generator 24 Hour Run and Load Rejection, Division I and II", revision 1, effective October 1987, performed on the Division I EDG on December 3, 1987.

No violations were noted.

5. 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:

5.1 Unit 1

-- Emergency Diesel Generators
-- Emergency Service Water
-- Containment Spray
-- Core Spray

5.2 Unit 2

-- Emergency Diesel Generators
-- Residual Heat Removal
-- Standby Gas Treatment

No violations were noted.

6. 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 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)

6.1 Unit 2

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

-- 87-21, 4/30/87, Potential failure of Clow butterfly valves due to movement of stem spline.

-- 87-24, 5/17/87, Two automatic starts of Standby Gas Treatment system due to low flow in normal reactor building ventilation system.

-- 87-25, 5/19/87, Secondary containment isolation during surveillance.

-- 87-30, 5/29/87, Primary containment purge isolation due to loss of gaseous radiation monitor.

-- 87-31, revision 1, 5/29/87, Reactor scram caused by power excursion due to failed feedwater control valve.

-- 87-37, 6/24/87, Main steam tunnel differential temperature instruments inoperable due to design deficiency.

-- 87-38, 8/7/87, RCIC steam line isolation.

-- 87-39, 6/30/87, Diesel generator room fan removed from service.

-- 87-43, 7/11/87, Reactor scram due to EHC tubing rupture.

-- 87-44, 7/25/87, Plant shutdown due to high service water inlet temperature.

-- 87-46, 7/30/87, Mode 1 surveillances not completed prior to entering Mode 1.

-- 87-48, 8/9/87, Shutdown cooling system isolation.

-- 87-50, 8/29/87, Automatic start of SBGT.

-- 87-62, 10/8/87, Failure of plant personnel to recognize that LPCI surveillance test acceptance criteria not met.

-- 87-67, 10/23/87, LCO exceeded due to TS misinterpretation.

-- 87-70, 10/27/87, Manufacturing deficiency results in an inoperable airlock door.

-- 87-72, 10/28/87, Containment isolation and SBGT initiation during ground isolation.

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

-- 87-22, 5/2/87, Loss of emergency DC power supply during surveillance.

-- 87-23, 5/9/87, Shutdown cooling system isolation due to operation of differential pressure detector isolation valves.

-- 87-28, 5/26/87, TS violation due to failure to test drywell personnel hatch door equalizing valve.

-- 87-29, 6/3/87, Automatic start of SBGT due to electronic spiking.

-- 87-36, 7/25/87, Automatic start of SBGT.

-- 87-45, 7/29/87, Automatic start of SBGT.

-- 87-47, 8/6/87, RWCU isolation due to high differential flow.

-- 87-68, 10/20/87, RWCU isolation due to personnel error; inattention to detail.

c. For the following LER, the licensee has committed to issue a supplemental report, this report will be reviewed in a subsequent inspection period:

-- 87-49, 8/25/87, Automatic start of SBGT due to low flow condition.

7. Three Mile Island Action Plan Items

As a result of the Three Mile Island (TMI) plant accident, generic reactor enhancements were developed by the NRC. NUREG-0737 documents the specific action requirements. The following TMI issues were reviewed during this inspection period:

7.1 Unit 1

a. (Closed) I.A.1.3 - Minimum Shift Crew. NUREG 0737 provided guidance on the minimum shift operating crew. Later, regulatory requirements on this were included in 10 CFR 50.54(m)(2)(i). The inspector reviewed the Technical Specifications (TS) and Administrative Procedure (AP)-4.0, Administration of Operations. After review of the notes on the tables in the TS and 10 CFR 50.54(m)(2)(i), the inspector concluded a minor inconsistency existed. Specifically, the TS requires only one licensed reactor operator (RO) when the reactor is in the hot shutdown condition, while 10 CFR 50.54(m)(2)(i) requires two ROs while the reactor is in hot shutdown. In discussion with the inspector, the Unit 1 Operations Superintendent stated that although apparently permitted by the TS, Unit 1 always maintains a minimum of two ROs on all shifts no matter what the reactor condition. The inspector discussed the discrepancy with the Licensing manager for Unit 1 and noted that, as a higher tier requirement, 10 CFR 50.54 (m)(2)(i) would take precedence. The licensing manager agreed that the discrepancy existed and stated that he would initiate action to correct the discrepancy. Based on the requirements in 10 CFR 50.54(m)(2)(i), this TMI item is closed. The inspectors will review licensee resolution of the TS discrepancy in a subsequent inspection period.

b. (Closed) II.D.3 - Direct Indication of Relief and Safety Valve Position. Inspection Reports 50-220/80-18 and 50-220/81-27 reviewed the acoustic monitoring system designed to provide direct indication of relief and safety valve positions. The inspectors found the installed equipment and procedures to be acceptable, with the exception that the process computer points were not reflected in the operating procedure. The inspector reviewed procedure N1-OP-1, Nuclear Steam Supply System, Revision 31, which discusses the computer points in section G.5, Stuck Open ERV and section H.15, Main Steam Electromatic Relief Valve Open (alarm response). Based on the above reviews, this item is closed.

c. (Open) II.F.2 - Instrumentation for Detection of Inadequate Core Cooling. Inspection Report 50-220/83-18 reviewed the wide range reactor vessel water level indication system, which shows level from the normal operating range to the bottom of the core. The inspectors found the system to be acceptable, except that the tie-in

to the process computer was not yet completed. The inspector determined that the computer tie-in had been completed and observed the wide range reactor vessel level on the core cooling display of SPDS. The inspector reviewed instrument procedures N1-ICP-36-ICC and N1-ISP-M-036-001, both titled Inadequate Core Cooling Reactor Core Level Indication, which check the computer tie-in on a refueling and monthly basis, respectively. The inspector reviewed an NRC letter dated May 24, 1987, which stated that Niagara Mohawk's two actions for Generic Letter 84-23 and TMI item II.F.2 were acceptable. Specifically, these actions were the installation of the wide range level system and the triple low level setpoint change (TS Amendment 64 of October 2, 1984). However, the NRC letter also stated that "you (Niagara Mohawk) have committed to perform a more fundamental program considering the S. Levy, Inc. report and have it scheduled for completion at the Spring 1986 refueling." The inspector determined that the program was never completed. The Unit 1 Licensing manager stated that the program would be completed in the Spring of 1988. This item remains open pending completion of actions associated with the above program.

d. (Closed) II.K.3.18 - ADS Logic Modification. NUREG 0737 requested that the logic of the Automatic Depressurization System (ADS) be modified to remove the high drywell pressure permissive. NRC letter dated January 22, 1985 approved Niagara Mohawk's position that for plants with isolation condensers, the logic modification would adversely impact safety during some accident scenarios and would provide "no clear overall safety enhancement." The letter concluded that no modifications to the ADS logic are required. Accordingly, this item is closed.

e. (Closed) II.K.3.19 - Interlock Recirculation Pump Isolation Valves. NUREG 0737 requested that for plants without jet pumps, the recirculation pump isolation valves be interlocked to assure that reactor water level indication would not be isolated from the reactor core upon recirculation loop isolation. NRC letter dated February 12, 1982 accepted Niagara Mohawk's approach of installing reactor level instrumentation (see II.F.2 above), which uses taps on the lower core plate and cannot be isolated from the core. The NRC staff also agreed that no interlock was needed. Accordingly, this item is closed.

f. (Closed) III.D.3.4 - Control Room Habitability. NUREG 0737 requested that the control room operators be protected against the effects of radioactive gases. During the 1984 outage, Niagara Mohawk modified the existing control room ventilation system by adding redundant intake dampers, redundant control room isolation dampers, redundant cooling water coils, redundant radiation monitors, and controls to actuate the added equipment. Also, seven self-contained breathing apparatus (SCBAs) were provided for

operator use in the control room. The inspector reviewed the installed equipment, the NRR Safety Evaluation dated May 21, 1984, the NMPC safety evaluation, the modification work package including quality control and preoperational testing records, P&ID drawing C-18047-C, operating procedure N1-OP-49, surveillance procedures N1-ST-M9, N1-ST-C9, and N1-RSP6C, and the revised Technical Specifications.

One minor problem needed correction. The modification package specified that seven SCBAs be provided for the use of the control room operators. However, when the inspector asked the operators to see the SCBAs they would use in an emergency, they were only aware of the two bottled air cylinders. Eventually, they pointed out a cabinet with six SCBAs that they believed were provided for fire protection purposes. Following discussions with plant management, these problems were corrected by providing a seventh SCBA, revising procedure EPMP-2 to inventory seven (not six) SCBAs, issuing an operator Night Order to reemphasize that the SCBAs were provided for the operators' use, and issuing a Training Modification Request (TMR) to provide requalification training on this message.

Based on the above review, the inspector concluded that the control room ventilation system had been modified in accordance with the Safety Evaluation and that the guidance of TMI item III.D.3.4 had been met. Accordingly, this item is closed.

No violations were identified.

8. Review of the Scram Discharge Volume Design - Unit 1

On June 28, 1980, during a routine shutdown of the Browns Ferry Unit 3 reactor, a manual scram from 36% power failed to insert approximately 40% of the control rods. The cause of this event was isolated to a design problem with the scram discharge header. Followup to this event at other BWRs revealed a number of similar deficiencies at other plants.

During December 1980, the NRC issued a Generic Safety Evaluation for BWR Scram Discharge Volumes (SDV). In this evaluation, the NRC established criteria for the design and testing of SDVs. In October 1980, the licensee had commented on several proposals for this safety evaluation and made commitments to implement several of the requirements.

The inspector determined that on January 30, 1981 the licensee submitted a letter to the NRC staff stating that NMPC was taking exception to three criteria of the Generic Safety Evaluation. Inspector followup of this letter determined that one of the exceptions involving the installation of diverse level instrumentation appears to be adequately satisfied. The two remaining exceptions involve: 1) the SDV instrument volume level instrument taps for the reference legs being located at the top of the SDV piping vice the SER specified location in the vertical section of the instrument volume; and, 2) the exception taken to performing periodic reactor scram testing at approximately 50% control rod density.

In June 1983, the NRC issued a Confirmatory Order to Niagara Mohawk to comply with the December 1980 Safety Evaluation by September 30, 1984 or prior to operation in fuel cycle 8. Further, the Order stated that the licensee was to submit any alternative methods of resolving the SDV design problems to the NRC for review and approval. During the inspector's review, no documentation could be found dated subsequent to the June 1983 Order which revisited the exceptions described above.

At the conclusion of the inspection period, the NMPC Licensing staff and the NRC staff were reviewing the sequence of events leading to this apparent oversight. This issue will remain unresolved until it can be determined if the remaining exceptions to the Generic Safety Evaluation are in compliance with the June 1983 Confirmatory Order and are acceptable to the NRC staff. UNRESOLVED ITEM (50-220/87-24-02)

9. Part 21 Report Review

During this inspection period, the following 10CFR21 report was initiated by the licensee:

9.1 Unit 1

On October 26, 1987, the licensee informed Region I staff of a potential safety hazard dealing with valves manufactured by XOMOX Corporation having Limitorque model H-BC operators. The XOMOX Corp. notified the licensee that four and twelve inch plug-type valves have the potential for not operating due to the failure of the stem to operator engaging mechanism. The motor operator would still generate valve position indications, but the valve would not actually reposition.

The licensee has determined that six of these valves are presently in use. Four of the valves are in the containment spray raw water system. The valves are normally closed, but function to supply raw lake water backup to the emergency core cooling systems. Two of these valves allow lake water to be sprayed into the containment or to flood the torus. The other two valves allow lake water to be supplied to the core spray system, allowing flooding of the vessel if the normal core spray supply is lost. The remaining two valves allow pump down of the torus via the containment spray system to the radwaste processing system.

The inspector reviewed the Unit 1 Final Safety Analysis Report, Operating and Emergency Operating Procedures. These raw water valves are referenced in the FSAR, however, they are not included or taken credit for in the Design Basis Accident analysis. The inspector verified that the licensee has tagged the valves in the shut position to prevent their use. Operation of the valves may be permitted, but only under the explicit direction of the Station Shift Supervisor in the event of an emergency. The licensee plans to modify these valves during the 1988 refueling outage.

The inspector had no further questions.

10. Followup of Generic Letter 84-11

The inspector conducted a review of licensee actions taken to address Generic Letter 84-11, Inspections of Austenitic Stainless Steel Piping Welds Susceptible to Intergranular Stress Corrosion Cracking (IGSCC), issued on April 19, 1984. Generic Letter 84-11 is applicable to IGSCC susceptible piping four inches and over in diameter and in systems operating over 200 degrees F which are part of or connected to the reactor coolant pressure boundary. NRC Inspection and Enforcement Manual, Temporary Instruction 2515/89, summarizes NRC inspection guidance to verify licensee completion of the activities required by Generic Letter 84-11.

10.1 Unit 1

a. The recirculation system piping was replaced with material resistant to IGSCC during the 1982 outage, minimizing the number of welds to which Generic Letter 84-11 is applicable. The scope of volumetric and surface examination of pipe welds is covered by the Inservice Inspection Program and augmented inspection requirements. For Unit I, the ASME Code, Section XI (summer 1983 addenda), Generic Letter 84-11 and NUREG 0313, revision 1, are applicable to piping welds susceptible to IGSCC.

Each of these three standards requires a different, but overlapping set of inspections. The inspector reviewed portions of the ISI program, including augmented inspections, and noted that the volumetric or ultrasonic examination (UT) requirements of Generic Letter 84-11 are included. The competence of UT examiners to detect IGSCC, as verified by performance demonstrations at EPRI, was reviewed. UT procedure 80A 2818, revision 7, provides that examination crews consist of a minimum of two persons, one of which is a Level II with IGSCC detection qualifications. The procedure also states that Level I personnel shall not be utilized for scanning or CRT screen signal evaluation, while scanning is being performed.

The inspector reviewed UT documentation of three pipe sizes (12, 24 and 16 inches) and the documentation of six UT examiners to determine that their capability to find IGSCC had been demonstrated at EPRI prior to performing the Generic Letter 84-11 inspections during the 1986 outages. Other weld examination documentation was sampled to establish that the documentation examined, in detail, was typical of all ISI documentation.

b. In addition to reviewing ISI program requirements for IGSCC identification, the inspector verified operational guidance was provided and understood. Technical Specifications (Amendment 70) provide that the reactor be placed in cold shutdown within 24 hours if unidentified leakage increases by 2 GPM over a 24 hour period or associated leak measurement equipment becomes inoperable. This specification was discussed with several licensed operators who were all familiar with the requirement.

c. For visual examination during each outage, where the containment is deinerted for Operations and Maintenance Department personnel entry, the inspector noted that a specific detailed visual inspection for reactor coolant piping leakage was not required by plant Operating, QA or ISI procedures.

d. Where IGSCC cracking is identified, the site practice is to evaluate the cracking to the ASME Code IWB 3514-2 (1980 edition) criteria and to not expand the inspection scope, if the IGSCC dimensions are acceptable to this portion of the ASME code. This position is not consistent with the Generic Letter 84-11 philosophy, which advocates that the detection of new cracks or crack growth requires an expansion of the inspection scope. During the 1986 outage, IGSCC identified in core spray piping was found acceptable to IWB 3514-2, however, 100% of the core spray piping welds were already scheduled for examination by the augmented portion of the ISI program.

e. The inspector concluded that the intent of Generic Letter 84-11 in detecting IGSCC in susceptible piping was being met at Unit 1, however, the procedures do not clearly address visual inspection requirements during brief outages where the containment is deinerted. In addition, the provision to expand the examination sample scope was not considered applicable, by the licensee, for cracking found acceptable to the ASME Code, Section XI, IWB 3514-2.

10.2 Unit 2

a. The austenitic piping at Unit 2, over four inches in diameter in systems operated above 200 degrees F, was constructed of material considered not susceptible to IGSCC. As such, Generic Letter 84-11 was not applicable. The Ten Year ISI Program Plan, Part 1.3.6, states that the augmented inspections of NUREG 0313, Revision 1, are not applicable to Unit 2, as referenced in the FSAR, Section 5.2.3.4.1. The initial ISI outage date for Unit 2 is mid-1989, however, the purchase order and procedures for volumetric examination of austenitic stainless steel piping were available. These procedures (83A 1766 and 80A 7718) provided for the use of EPRI qualified UT examiners to detect IGSCC, should it occur during the first operating cycle. However, the use of IGSCC qualified UT examiners was not provided for by the licensee's procedures beyond the first refuel cycle inspection. The inspector determined that the Preservice Ultrasonic Examination work at Unit 2 did use IGSCC qualified examiners and acceptable procedures to provide a baseline set of data.

b. The inspector concluded that the licensee has taken steps to prevent Unit 2 IGSCC by providing non-susceptible materials and an adequate water chemistry control program. The licensee is presently including IGSCC detection capability in ISI program activities by the use of IGSCC qualified UT personnel and appropriate inspection procedures.

No violations were identified.

11. Condensate Storage Tank Rupture - Unit 2

On November 28, the A Condensate Storage Tank (CST) ruptured and the contents of the tank drained into the CST Building. Based on inspection of the applicable equipment, including the interior of the CST and discussions with Niagara Mohawk personnel, the inspector determined the following:

11.1 Tank

There are two CSTs, each 40 feet in diameter and 60 feet high. The tanks, fabricated and installed by Metal Cladding, Inc., are constructed of 1/4" fiberglass wrapped with a continuous 7/8" cable and have a 500,000 gallon capacity. The A CST is connected to the Reactor Core Isolation Cooling (RCIC) System suction, while the B CST is connected to the High Pressure Core Spray (HPCS) System suction. The rupture in the A CST occurred as a 20 foot split in the fiberglass seam between the tank side wall and the rounded corner piece which bridges between the side wall and the bottom. During installation, irregularity in the concrete floor had caused the tank to be crooked, and the side wall in the vicinity of the rupture had been shimmed up to correct the irregularity. Following the rupture, Metal Cladding concluded that this installation problem was the primary cause of the tank failure.

Niagara Mohawk decided to repair the tank by removing the full circumference of the corner piece and installing a new piece. Following the repair, the fiberglass joint will be visually inspected and hydrotested under full load. Acoustic monitoring of the tank is being evaluated, as is the internal visual inspection of the B CST.

11.2 Safety Significance

Although the CSTs are the primary source of water for the RCIC and HPCS Systems, the CSTs are not part of the design basis for the reactor. The design basis assumes that these systems will use the suppression pool as their water source. Accordingly, the CSTs are not safety-related and not seismically designed. The Technical Specifications address the instrumentation and the isolation valves associated with the suction changeover from the CSTs to the suppression pool.

11.3 Scenario

The leak was discovered after 6 p.m. on November 28 when a high level alarm annunciated in the control room concerning the sump in the pipe tunnel adjacent to the CST building. A radwaste operator sent to investigate found standing water in the 14 foot deep pit surrounding the CSTs. During this event, the water reached a depth in the pit of approximately one and a half feet. The floor drain from the pit drains to a sump in the adjacent pipe tunnel. The CST water exceeded the 100 gpm pumping capacity of this sump and flooded into the pipe tunnel. Thereafter, the water in the pipe tunnel flowed into a 40 ft. deep pipe chase to the lower floors of the Reactor Building. When one of the four pipe penetration seals into the Reactor Building failed, water flowed into the ground floor of the Reactor Building.

After concluding that the A CST had ruptured, the Station Shift Supervisor (SSS) initiated actions to isolate the A CST from the B CST and all inputs, to pump condensate from the A CST to the B CST, and to gravity drain condensate into the suppression pool. Despite these efforts, approximately 300,000 gallons drained into the CST pit. The floor drain was covered and following water sampling, the CST water was pumped outside the CST Building using portable pumps.

Later, Niagara Mohawk concluded that the CST pit area floor drain should not have been open, and efforts were underway to provide a watertight drain plug.

11.4 Pipe Boot Seal

The pipe penetration boot seals are band clamped and glued to the pipe sleeve in the Reactor Building wall and to the pipe. The boot seals are fabricated by ICMS and are made of a silicon rubber material. The seal was designed to withstand a 28 psi pressure, but one seal failed under the calculated load of 15 psi. Niagara Mohawk evaluations of the failed boot seal concluded that workers had stood on the boot seal while installing a conduit above the pipe and had degraded the seal. The other three seals, which withstood the 15 psi load, were inspected and found to be undamaged. Initial evaluations determined that the degraded seal had existed for over a year, but had not resulted in an inoperable secondary containment. This conclusion was based on an acceptable negative pressure in the secondary containment having been demonstrated numerous times.

11.5 Reportability

The NRC was not notified of this event via the Emergency Notification System (ENS), as NMP-2 determined that notification was not required. The inspector reviewed Occurrence Report 87-244 which documented the event and that notification was not required. Niagara Mohawk is performing an evaluation concerning reportability of the boot seal's failure under Part 21. In discussions with the inspector, the Unit 2 Station Superintendent agreed that, although not required, a voluntary LER would be submitted to describe the event.

11.6 Findings

a. The inspector concluded that Niagara Mohawk's resolution of the CST rupture, thus far, was acceptable and appropriate. The acceptability of the repairs, the testing of the two CSTs, and the ongoing evaluations will be reviewed in a future inspection report as part of the LER review.

b. The inspector noted that the control room annunciator for high CST level is routinely lit, because the alarm was designed with an assumed normal level of approximately 25 ft.. However, operating personnel usually maintain the CST level at approximately 40 ft., well above the 27 ft. alarm setpoint. The repair and testing of the two CSTs appeared to provide an opportunity to correct this situation. In discussions with the inspector, the Unit 2 Operations Superintendent agreed to review the CST high level alarm as part of the event analysis. He also noted that it was included in the ongoing review of unnecessary/nuisance alarms.

c. The inspector concluded that Niagara Mohawk's approach to resolution of the event was effective, in that a task force was established under an engineering manager with Operations, Maintenance, and Site Engineering Departments included on the task force.

No violations were identified.

12. Licensee Action on IE Bulletins and Information Notices

The inspector reviewed licensee records relating to the IE Bulletins and Notices identified below to verify that: the IE Bulletins and Notices were received and reviewed for applicability; written responses were provided, if required; and the corrective action taken was adequate.

12.1 Unit 1 and Unit 2

IE Bulletin 87-01: Thinning of Pipe Walls in Nuclear Power Plants. The purpose of this bulletin was to request that licensees submit information concerning their programs for monitoring the thickness of pipe welds in high-energy single-phase and two-phase carbon steel piping systems. The basis for this request was the conclusion that the catastrophic failure of a main feedwater pipe at the Surry Power Station, Unit 2, on December 9, 1986, was the result of erosion/corrosion of the carbon steel pipe wall. The NRC staff intends to summarize the information collected per this IE Bulletin and study it to help determine if additional actions are required by the staff and/or industry.

The inspector reviewed the licensee's Unit 1 and Unit 2 responses (NMP1L-1087 and NMP2L-1077), dated September 14, 1987, to IE Bulletin 87-01 and verified that the licensee adequately addressed the questions asked. In addition, the inspector reviewed the Unit 1 and Unit 2 Project Reports for "Carbon Steel Piping Systems Erosion-Corrosion Review Program". These Project Reports are formal, written proposals submitted to NMPC senior management for review and approval of the stated programs. The inspector confirmed, with licensee station management, that these programs were approved and received funding for the coming fiscal year.

The inspector will monitor implementation of these programs as part of the routine review of unit outage activities. This bulletin is closed.

13. Inspection Summary - Assurance of Quality

The Unit 1 LSSS violation indicates a lack of formal review of reactor thermal limit evaluations by the licensed Operations staff. Licensee efforts to provide and improve the Emergency Notification Siren monitoring system are commendable. Licensee efforts to ensure NRC commitments are properly tracked need further management attention. Licensee efforts to ensure satisfactory compliance with the SDV Generic Safety Evaluation appear to have been cursory. NMPC initiative to develop and implement a comprehensive erosion/corrosion examination program (IE Bulletin 87-01 response) is strongly endorsed. Licensee efforts to address IGSCC are satisfactory.

14. 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.