U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/97-01 50-410/97-01
License Nos.:	DPR-63 NPF-69
Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	January 12 - February 22, 1997
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EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/97-01 & 50-410/97-01
January 12 - February 22, 1997

This integrated inspection report includes reviews of Niagara Mohawk Power Corporation (NMPC) activities in the areas of operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

PLANT OPERATIONS

NMPC identification of an increased drywell floor drain leakage rate at Unit 1 and the subsequent reactor shutdown for repairs were appropriate. Control rod drive housing support gap verification, in response to a Unit 2 issue, was prudent and identified no discrepancies. The ability of the Unit 1 operators to control reactor vessel water level during the shutdown was improved.

The inspectors conducted a detailed review of both control rooms and noted that safety systems were aligned properly, and appropriate Technical Specification (TS) Limiting Condition of Operation (LCO) actions were implemented. Shift personnel were knowledgeable of the reasons for anomalous indications and annunciators. The inspectors noted an excellent control room environment in Unit 2, with a marked improvement in Unit 1 control room. In both units, the staff routinely exhibited formal three-part communications; access was limited; annunciator response was appropriate; and shift supervision demonstrated good command and control.

In Unit 1, the process for identifying, tracking, and resolving control room deficiencies appeared adequately managed. Most control room deficiencies were resolved in a timely manner, although a few defeated annunciators from 1995 were awaiting final resolution. Current operator work-arounds appeared to have no adverse impact on safe plant operation.

The material condition and equipment labeling of the Unit 2 high pressure core spray system and the associated Division III emergency diesel generator was good. Both systems have demonstrated a high level of reliability. NMPC staff performed surveillance tests in accordance with approved procedures and utilized good three-part communication. A weakness in management oversight of long-standing deficiencies was noted, in that an excessive amount of time was required to address a human-factors concern associated with disconnected local valve position indications.

MAINTENANCE

The Unit 1 maintenance personnel performing new fuel inspections had adequate knowledge for the assigned duties and responsibilities. The handling and movement of the new fuel into the spent fuel pool was controlled, and the NMPC staff was knowledgeable of procedural requirements. Measuring and test equipment (M&TE) were within calibration

periodicity, although a weakness was noted in the ability to readily ascertain vendor-provided M&TE calibration due dates.

Poor oversight by Unit 2 operations and maintenance management allowed the standby gas treatment system (GTS) "B" cross-connect valve to be failed open for fourteen months. Subsequently, inadequate work planning permitted the "A" cross-connect valve to be failed open at the same time. The inspectors questioned whether both valves open met the requirements of the Technical Specifications. (URI 97-01-01) Also, the inspectors identified a plant design change made to GTS during initial operation, which was not reflected in the Unit 2 Updated Final Safety Analysis Report. (Non-Cited Violation (NCV))

ENGINEERING

NMPC identified that some pipe supports inside containment for the Unit 1 reactor building closed loop cooling water system were outside of the design basis for seismic considerations. NMPC determined the supports were operable in that they met stress requirements of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix F. NMPC plans to repair the supports during the next refueling outage.

An NRC inspection of C&D Charter Power Systems, Inc. (a supplier of lead-acid storage batteries to NMPC for safety-related applications) identified several concerns related to the implementation of the C&D quality assurance program. The NRC noted that an NMPC audit of C&D in August 1994 had not identified the problems that the NRC found, which suggested a possible weakness in the effectiveness of NMPC's audit process. (URI 97-01-02) In addition, the NRC questioned the operability of any C&D batteries supplied for NMPC. (URI 97-01-03) Finally, NMPC initially stated that only Unit 1 was using C&D batteries; subsequently, the licensee informed the inspectors that at least one additional use of C&D batteries was at Unit 2. This caused the inspectors to be concerned with the ability of NMPC to identify the location and use of purchased equipment. (URI 97-01-04)

The licensee took appropriate action after determining that Unit 2 reactor core isolation cooling (RCIC) system motor-operated valves (MOVs), operated from the remote shutdown panel, did not have adequate redundancy in the event of a fire-induced hot-short. However, a weakness existed in that NMPC failed to recognize the inadequate redundancy upon determining RCIC MOV susceptibility to hot-shorts; particularly, since the lack of procedures for accomplishing the alternate method of safe-shutdown had been previously identified and documented.

As part of a continuing review of NRC Generic Letter (GL) 96-06, NMPC identified several piping segments at both units that could be overpressurized during a design-basis loss-of-coolant accident. Operability determinations were adequate and consistent with the guidance provided in the GL. The licensee demonstrated a good questioning attitude by identifying potential overpressure concerns resulting from situations not readily apparent from the guidance provided in the GL.

Executive Summary (cont'd)

In Unit 1, the failure to identify and include containment vacuum relief breaker local leak rate test ports in the Appendix J program since 1983 violated TS Surveillance Requirements. (NCV) However, the relief breakers had been operable the entire time with respect to the ability to perform their intended safety function, as evidenced by successful surveillance testing.

During a Unit 2 refueling outage, both divisions of the service water system were inoperable for several hours during maintenance activities which resulted in a violation of Unit 2 TSs. (NCV)

Licensee actions to correct the repetitive and premature failure of containment monitoring system pump diaphragms were appropriate and resulted in a Part 21 report being written by the vendor.

The Independent Safety Engineering Group identification of an inadequate Part 21 determination pertaining to an improperly peened dowel pin in a GTS valve was very good. However, the inspectors noted that the level of detail in the Deviation/Event Report (DER) procedure for Part 21 initial screening was weak and would have resulted in a failure of a Part 21 concern to receive timely review, if not for the identification by the ISEG.

During the review of a 1994 unresolved item pertaining to incorrect fuses installed in the Unit 2 RPS, the inspectors determined licensee performance to be weak; in that, without proper justification, a sample size of 5% was too small to adequately assess the extent of the problem. Also, in 1995, when the licensee identified an additional fuse discrepancy, it was not addressed by the DER process, as required by procedure, and resulted in a failure to determine a root cause. (NCV) The failure to ensure that the installed fuse configuration was consistent with controlled drawings was a violation of 10 CFR 50, Appendix B, Criterion V. (NCV) The current fuse control program appears adequate.

PLANT SUPPORT

General housekeeping and material storage in the Unit 2 radiological waste facility were good. Also, flammable liquids within the facility had been appropriately evaluated, in accordance with the licensee's fire protection program.

NMPC identified that meteorological instrumentation had been inoperable since initial installation, but a special report was not submitted at that time. As such, Unit 2 had been operating in a condition outside the TSs. (NCV)

Licensee efforts to maintain fire suppression equipment and plant areas in a condition to support fire prevention, detection, and suppression were good. However, an inspector identified in the Unit 2 control building that a check valve was used for isolation when one of the two halon tanks was removed for maintenance. The existing markup procedure appeared weak, in that it did not preclude the use of a single check valve as personnel protection from hazardous conditions.

REPORT DETAILS

Nine Mile Point Units 1 and 2
50-220/97-01 & 50-410/97-01
January 12 - February 22, 1997

SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) started the inspection period at full power. On January 17, Unit 1 was shutdown because of increasing drywell floor drain leakage. Unit 1 was restarted on January 19, following repairs; full power was achieved on January 20. On February 12, Unit 1 reached the condition of all control rods fully withdrawn and started a coastdown in power as they neared the next refueling outage, scheduled to commence March 3. Unit 1 ended the period at 95% power.

Unit 2

Nine Mile Point Unit 2 (Unit 2) started the inspection period at full power. On February 1, power was reduced to 66% for a rod sequence exchange; full power operation was restored 29 hours later. On February 14, power was reduced to 80% for control rod scram time testing; power was returned to 100% seven hours later. The unit maintained essentially full power for the remainder of the inspection period.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC conducted inspection activities during normal, backshift, and deep backshift hours. The results are contained in the applicable sections of this report.

Updated Final Safety Analysis Report (UFSAR) Reviews

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with UFSAR commitments. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. The inspectors noted one exception where a Unit 2 standby gas treatment system plant design change was not properly reflected in the UFSAR (Section M7.1).

I. OPERATIONS

O1 Conduct of Operations (71707) [1]

O1.1 General Comments

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

O1.2 Unit 1 Reactor Shutdown Resulting from Increased Drywell Floor Drain Leakage

a. Inspection Scope

On January 15, 1997, Unit 1 operations staff identified an increase in drywell floor drain (DWFD) leakage. The inspectors observed the licensee's response to the leakage.

b. Observations and Findings

As a result of the increasing DWFD leakage rate, Unit 1 management concluded that the leakage rate would eventually exceed the Technical Specification (TS) limit, requiring a reactor shutdown. Therefore, before reaching the TS limit, the reactor was shutdown on January 17. The inspectors considered the licensee's actions appropriate.

The licensee conducted a drywell entry and identified valve packing leakage on an instrument line for the #15 reactor recirculation pump. The valve was subsequently repacked. Additionally, maintenance staff performed a control rod drive (CRD) housing support (commonly referred to as "shoot-out steel") gap inspection. No shootout steel gap discrepancies were identified. The inspectors considered this action prudent due to the recent Unit 2 issue discussed in NRC Inspection Report (IR) 50-410/96-14. Unit 1 was restarted on January 19 and achieved full power on January 20.

c. Conclusions

NMPC's identification of increased DWFD leakage and subsequent reactor shutdown were appropriate. CRD housing support gap verification was prudent and identified no discrepancies.

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

O1.3 Control of Reactor Vessel Water Level During Unit 1 Reactor Shutdown

Recent NRC inspection reports noted that some Unit 1 operators had experienced difficulty in controlling reactor vessel water level during a normal plant shutdown and after an unplanned reactor scram. The inspectors reviewed the strip-chart recorder traces of reactor level and feedwater flow associated with the shutdown of January 17. As part of the normal shutdown procedure, a manual reactor scram was inserted with power between 20 and 25 percent. Reactor vessel water level was about 70 inches before the scram; following the scram, level decreased to 40 inches and returned to the pre-scram level within six minutes. Discussions with shift management and review of the traces indicated an improved ability by the operators to control reactor vessel water level during a normal shutdown.

O2 Operational Status of Facilities and Equipment

O2.1 Verification of Control Room Switches and Indications

a. Inspection Scope

The inspectors performed a detailed comparison of the operating panels in both control rooms against a checklist of expected normal indications and switch positions. The Operational Safety Verification (OSV) Checklists were developed by the inspectors using, as a basis, the operators' daily logs, the Technical Specifications (TS), the Updated Final Safety Analysis Report (UFSAR), and system operating procedures. The inspectors normally compare the status of indications and controls to the OSV Checklist once per inspection period.

b. Observations and Findings

Using the OSV Checklists, the inspectors reviewed the Unit 1 and Unit 2 control room switch positions and indications on January 29 and January 30, 1997, respectively. During the OSVs, both units were at full power and safety systems were aligned properly for full power operations. All differences between the OSV Checklist and actual plant status were verified for those systems removed from service for maintenance, and the inspectors verified that any applicable actions were implemented for the respective TS Limiting Condition of Operation (LCO). The inspectors also verified that shift personnel were knowledgeable of the reasons for the anomalous indications and annunciators.

While performing the OSV Checklist, the inspectors verified that shift staffing was in compliance with TS requirements. The inspectors noted that staff in both units exhibited formal communications. The use of three-part communication in Unit 2 has been very consistent; three-part communication in Unit 1, although improving, was still inconsistent. Three-part communication is a process consisting of a statement, repeat back of the statement, and acknowledgement confirming an acceptable repeat back. Entry into the "at-the-controls" area was restricted. Operator annunciator response was appropriate; alarm response procedures were referenced, and shift supervision demonstrated good command and control.

The inspectors noted an excellent control room environment in Unit 2, in that only personnel requiring access to the at-the-controls area were present and promptly exited the area upon completion of duties. Although the inspectors have noted a marked improvement in the Unit 1 control room environment, shift personnel occasionally gather in the at-the-controls area without having a definitive need. The overall Unit 1 control room environment was good. The Unit 2 turnover briefing for the on-coming shift was thorough, with good two-way exchange of information between supervision and staff. The inspectors noted that the Unit 2 Operations Manager was present on this day, and both Operations Managers are frequently seen in their respective control rooms.

c. Conclusions

In both units, safety systems were aligned properly for current plant operations, and the appropriate TS LCO actions were implemented for unavailable equipment. Shift personnel were knowledgeable of the reasons for anomalous indications and annunciators. The environment in both control rooms continues to improve. In both units, the staff exhibited formal communications; access was limited; annunciator response was appropriate; and shift supervision demonstrated good command and control.

O2.2 Unit 1 Control Room Deficiency Review

a. Inspection Scope

The inspectors reviewed the Unit 1 system for identification, tracking, and resolution of control room deficiencies. Specifically, the inspectors focused on defeated annunciators and operator "work-arounds" in the Unit 1 control room. The inspectors reviewed the procedure governing temporary modifications, and the control room deficiency log, and discussed concerns with the Station Shift Supervisor (SSS) and plant management.

b. Observations and Findings

The inspectors reviewed licensee Procedure GAP-DES-03, "Control of Temporary Modifications," Revision 6, which controls the review, implementation, and clearance of temporary modifications. Section 3.4 of the procedure provided administrative guidance relative to defeated annunciators. The licensee defined a "defeated annunciator" as an annunciator window having a temporarily altered circuit because of a design deficiency, malfunctioning component, or markup for pre-planned maintenance. A defeated annunciator could have one, or all, inputs altered.

During the inspection period, the licensee had an average of ten control room annunciators defeated. Most defeated annunciators were originated in 1996; however, three annunciators were defeated in 1995. Defeated annunciators were generally resolved in a timely manner, although a few were awaiting resolution. Overall, the inspectors have noted a reduction in the defeated annunciator backlog

since the last quarter of 1996. In September 1996, the inspectors attended a management review meeting of current control room deficiencies; the reduction in the defeated annunciator backlog appeared to be due, in part, to this management review.

The inspectors reviewed the Defeated Annunciator Log maintained in the control room and determined that all were appropriately logged. Compensatory actions for those annunciators whose inputs were defeated were discussed with the control room staff. All defeated annunciators appeared to have one or more alternate means for readily identifying an abnormal occurrence.

The inspectors also reviewed the Operator Work-Around Log maintained in the control room and discussed the deficiencies with plant staff and management. The term "work-around" refers to actions performed by the operating crew to compensate for equipment not functioning as designed. Six work-arounds were listed, three of which directly affected control room operations. The inspectors concluded that the current work-arounds had no adverse impact on safe plant operations. The work-around program appeared to receive adequate management attention.

c. Conclusions

The licensee's process for identifying, tracking, and resolving Unit 1 control room deficiencies appeared adequately managed. Overall, control room deficiencies were resolved in a timely manner; however, a few defeated annunciators from 1995 were awaiting final resolution. Current operator work-arounds appeared to have no adverse impact on safe plant operation.

O2.3 Unit 2 High-Pressure Core Spray System ESF Walkdown

System Description

The high pressure core spray (HPCS) system is an emergency core cooling system (ECCS) for a loss-of-coolant accident (LOCA), and is designed to pump water into the reactor vessel over a wide range of pressures.

The HPCS system consists of a single motor-driven pump, a spray sparger in the reactor vessel located above the core, and associated system piping, valves, controls and instrumentation. The HPCS system, and support equipment, automatically initiates on a low reactor water level or high drywell pressure signal. The system can also be initiated manually. The HPCS pump initially takes a suction from the condensate storage tank (CST); the suction is automatically transferred to the suppression pool on low CST level or high suppression pool level. The system is designed to automatically secure on a high reactor water level signal, and to automatically restart upon receipt of a subsequent low reactor water level signal. The system is designed to be powered from offsite, or from the dedicated Division III emergency diesel generator (EDG) if offsite power is not available.

a. Inspection Scope

The inspectors assessed the ability of the HPCS system to perform the intended function. This assessment included a visual inspection (walkdown) of accessible portions of the HPCS system, the Division III EDG, and portions of the service water system supporting both the HPCS system and Division III EDG. The inspectors observed performance of surveillance tests and reviewed completed surveillance tests associated with the HPCS system, Division III EDG, and related actuation signals. The inspectors reviewed the HPCS and Division III EDG "System Health" reports, related Deviation/Event Reports (DERs), and applicable sections of the Unit 2 UFSAR, TSs, and operating procedures. The inspectors also reviewed the HPCS system and Division III EDG with respect to the Maintenance Rule (Title 10 of the Code of Federal Regulations Part 50.65 (10 CFR 50.65)). The inspectors discussed the issues with the system engineer, operators, operations management, and the Unit 2 Maintenance Rule Coordinator.

b. Observations and Findings

While accompanied by the system engineer, the inspectors performed a walkdown of accessible portions of the HPCS system. The inspectors compared plant drawings and Procedure N2-OP-33, "High Pressure Core Spray System," Revision 06, to the actual valve positions; no discrepancies were identified. The inspectors also verified that a recently installed modification to address pressure locking concerns with CSH*MOV118 (HPCS pump suction from the suppression pool isolation valve) was appropriately included within the procedure and that control room drawings correctly represented the installed configuration. The material condition of the equipment appeared to be good. The inspectors identified no valve leakage. Only one valve, CSH*MOV101 (HPCS pump suction from the CST isolation valve), had minor visible corrosion. Housekeeping and equipment labeling were good. The inspectors identified some hand tools and test equipment adrift; upon informing the licensee, appropriate actions were taken to properly store the gear.

During the walkdown of the HPCS system, the inspectors questioned the system engineer regarding a discrepancy between the control room and local valve indications for CSH*MOV118, and ascertained that the local valve indicator was disconnected. Discussions with the system engineer and the acting Operations Manager revealed that the chain-driven position indicators for this and approximately eleven other valves were removed prior to initial plant startup. The chains were removed to avoid a potential actuator failure due to the chain dislodging and falling into the actuator. The inspectors were concerned that there was no visible identification that the position indicators were not functioning, and there was the potential for inadvertent use by the operators. Although the licensee was aware of the concern, as evidenced by DER 2-94-0918, corrective actions had yet to be completed; moreover, the DER had been extended twice from the original due date of March 30, 1995, to the current due date of March 7, 1997. The inspectors consider this to be an excessive amount of time to address a human-

factors concern and indicates a weakness in management oversight of long-standing deficiencies.

The inspectors also walked down the Division III EDG and verified that the system configuration was in accordance with the Operating Procedure N2-OP-100B, "HPCS Diesel Generator," Revision 05. The inspectors also verified that the electrical circuit breakers, providing power to HPCS system loads, were in the proper position as described by the applicable operating procedures.

The inspectors reviewed completed surveillance tests associated with the HPCS system, the Division III EDG, and system actuation signals. The inspectors determined that the tests adequately included surveillance and testing requirements described in the TSs and UFSAR. The inspectors observed portions of four surveillance tests and one HPCS system motor-operated valve (MOV) dynamic test. The observed tests were completed in accordance with approved procedures. The operators and technicians performing the tests consistently used good three-part communication. However, minor human-factor weaknesses in the clarity of certain steps were identified in the "HPCS Pump and Valve Operability & System Integrity Test" (Procedure N2-OSP-CSH-Q002, Revision 00). These weaknesses were discussed with the acting Operations Manager. Subsequently, the licensee enhanced the procedure to address the weaknesses.

The inspectors reviewed the open DERs associated with the HPCS, Division III EDG and service water systems, and found the planned corrective actions appropriate; the schedule for completion appeared to appropriately consider reactor safety and system operability. The inspectors also reviewed a list of closed DERs, and selected a sample based on potential safety importance or apparent recurring problems. These DERs were reviewed and determined to be appropriately addressed by the licensee.

The inspectors reviewed the current "System Health Report" for the HPCS and EDG systems, and discussed system performance with the system engineer. The system engineer was knowledgeable of system and component history. There was no indication of required major corrective maintenance for the systems. A review of HPCS system parameters revealed no negative trends. The HPCS system and the Division III EDG were performing within the maintenance rule established acceptance criteria.

c. <u>Conclusions</u>

The system walkdowns and performance history reviews indicated that the material condition and equipment labeling of the HPCS system and the Division III EDG were good. Both systems have demonstrated a high level of reliability. NMPC staff used approved procedures and utilized good three-part communication during surveillance tests. However, the excessive amount of time required to address a human-factors concern associated with disconnected local valve position indications was considered a weakness in management oversight of long-standing deficiencies.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (60705, 60710, 61726, 62707)

M1.1 General Comments

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

- N1-MMP-FHP-003 New Fuel Bundle Inspection
- N1-MMP-FHP-004 New Fuel Bundle Channel Inspection, Cleaning, and Mating
- N1-MMP-FHP-005 Movement and Storage of New Fuel After Inspection
- N1-MPM-GEN-SA806 Inspection of Reactor Building Crane
- N1-FHP-9 Movement of New Fuel and Control Rod Blades Into the Spent Fuel Pool
- N2-OPS-RPS-W002 Manual Half Scram Channel Functional Test
- N2-OSP-EGS-M@002 Diesel Generator and Diesel Air Start Valve Operability Test - Division III
- N2-TTP-CSH-001 Dynamic Testing of 2CSH*MOV110 for Generic Letter (GL) 89-10
- N2-OSP-CSH-Q002 HPCS Pump and Valve Operability & System Integrity Test
- N2-OSP-CSH-R001 High Pressure Core Spray Functional and Response Time Test

The inspectors reviewed the following completed surveillance tests:

- N2-OSP-CSH-M001 HPCS Discharge Piping Fill and Valve Lineup Verification
- N2-OSP-CSH-Q001 High Pressure Core Spray Valve Operability Test
- N2-ISP-CSH-Q001 Quarterly Functional Test and Trip Unit Calibration of HPCS Suction Transfer on High Suppression Pool Level Instrument Channels
- N2-ISP-CSH-Q002 Quarterly Functional Test of the HPCS Pump P1 Discharge Pressure - High Bypass Instrument Channel
- N2-ISP-CSH-Q003 Quarterly Functional Test of the HPCS Pump Discharge Flow Instrument Channels
- N2-ISP-CSH-Q005 Quarterly Functional Test and Trip Unit Calibration of Condensate Storage Tank Level Low Instrumentation for HPCS Suction Transfer

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

• N2-ISP-CSH-Q006	Quarterly Functional Test and Trip Unit Calibration of HPCS Initiation on Drywell Pressure High Instrument Channels
• N2-ISP-CSH-Q007	Quarterly Functional Test and Trip Unit Calibration of HPCS Initiation On Reactor Vessel Water Level Low, Low Level 2 and Isolation on High Level 8 Instrument Channels
• N2-ISP-CSH-R105	Operating Cycle Calibration of Condensate Storage Tank Level Low Instrumentation for HPCS Suction Transfer
• N2-ISP-CSH-R106	Operating Cycle Calibration of HPCS Initiation on Drywell Pressure High Instrument Channels
• N2-OSP-CSH-R301	Logic System Functional Test of HPCS Injection Valve Closure on Reactor Vessel High Level 8 Trip
• N2-OSP-EGS-R005	Diesel Generator ECCS Start Division III
• N2-OSP-EGS-R006	Operating Cycle Diesel Generator 24 Hour Run and Load Rejection Test Division III
• N2-OSP-EGS-R007	Operating Cycle Diesel Generator Simulated Loss of Offsite Power Division III
• N2-OSP-EGS-R008	Operating Cycle Diesel Generator Simulated Loss of Offsite Power with an ECCS Division III Initiation

M1.2 New Fuel Inspection and Transfer to Spent Fuel Pool

a. Inspection Scope

The inspectors observed maintenance personnel perform new fuel bundle and channel inspections, and operations personnel transfer newly inspected fuel bundles to the spent fuel pool (SFP). The inspectors reviewed applicable NMPC procedures and discussed the details of the evolutions with maintenance and operations staff, and management.

b. Observations and Findings

During the inspection period, the inspectors observed maintenance personnel remove new fuel bundles from storage crates and transfer the bundles to the inspection stand. Maintenance supervision and radiological protection personnel were present during the evolution. Maintenance supervision had a thorough knowledge of the sequence of events and the requirements for the movement and inspection of the new fuel. Movement of the bundles was adequately controlled and in accordance with approved procedures. During the evolution, the inspectors noted that foreign material exclusion (FME) controls were in effect, and that maintenance personnel adhered to the FME requirements.

The inspectors discussed overhead crane, hoist and sling inspections with the maintenance supervisor. The supervisor stated that vendors assisted NMPC maintenance personnel in conducting the periodic overhead crane inspection. The reactor building overhead crane had been inspected on January 10, which met the periodicity requirement stated in Procedure N1-MPM-GEN-SA806. As required by procedure, the slings, shackles, and eye-bolts were inspected prior to use. Furthermore, the torque on the 1000-pound hoist jam-nut was verified shiftly, as an

added precaution in response to a dropped fuel bundle event at another facility, in which this nut had become loose.

The inspectors discussed with the maintenance supervisor the training requirements for performing new fuel inspection. The supervisor stated that initial formalized training was conducted by the vendor, General Electric (GE), who certified the NMPC new fuel inspectors. Both classroom and hands-on training were provided. NMPC conducted refresher training as part of the pre-job brief for new shipment inspection. Maintenance personnel were rotated between fuel inspection and fuel handling to deter complacency. The inspectors considered the refresher training and personnel rotation approaches appropriate.

The inspectors verified that NMPC measuring and test equipment (M&TE) was within required calibration periodicity. However, GE-provided M&TE calibration due dates were not readily interpretable (e.g. a due date of "16-97"). The inspectors questioned the maintenance supervisor whether this GE-provided M&TE was within calibration periodicity. Initially, the supervisor was uncertain, but further investigation and communication with GE revealed that "16-97" indicated a calibration due date during the sixteenth week of calendar year 1997 (i.e. mid-April 1997). The inspectors consider it a weakness that the maintenance supervisor failed to recognize that the GE-provided M&TE calibration due dates were not readily interpretable for equipment in use for several months. This is indicative of a lack of a questioning attitude.

The inspectors observed operations personnel transfer new fuel bundles into the SFP. The evolution was adequately controlled and performed in accordance with the approved NMPC procedure. Required M&TE calibrations were current and pre-evolution inspections on the overhead crane and grapple had been performed or were within periodicity. Personnel performing the evolution were qualified and knowledgeable.

c. <u>Conclusions</u>

Maintenance personnel appeared to have adequate training and knowledge for performing new fuel inspection and handling. M&TE were within calibration periodicity, although a weakness was noted in the ability to readily ascertain the calibration due dates of vendor-provided M&TE. Movement of new fuel into the SFP was controlled, and the staff was knowledgeable regarding procedural requirements.

M7 Quality Assurance in Maintenance Activities

M7.1 <u>Unit 2 Standby Gas Treatment System Inoperable During Maintenance</u>

a. <u>Inspection Scope</u>

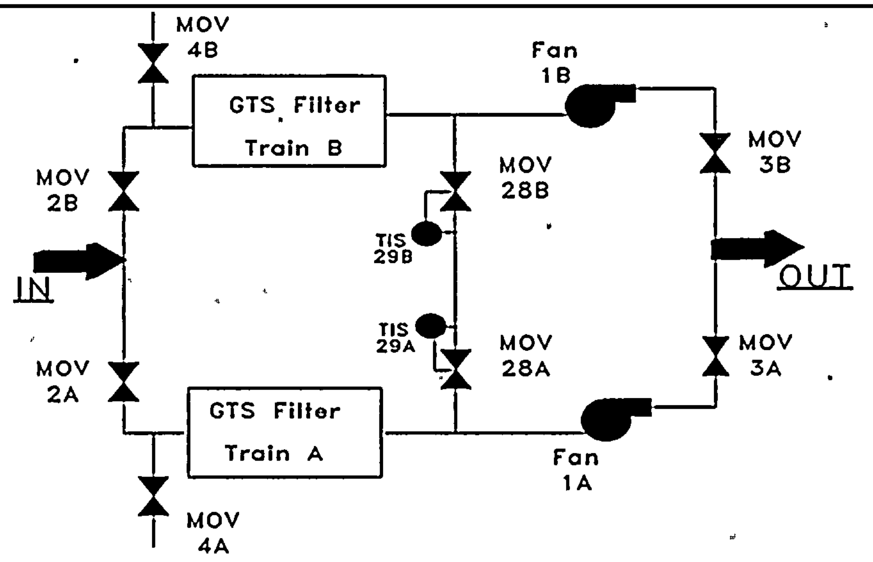
During a DER review, NMPC determined that both trains of the Unit 2 standby gas treatment system (GTS) were inoperable and unable to perform the intended safety

function for several days, due to both cross-connect valves being failed open. An engineering analysis later determined that both trains were operable. The inspectors reviewed the DER, the associated event notification, the GTS operating procedure, associated engineering documents, and the applicable sections of the TSs and the UFSAR. The inspectors also walked down the system and discussed the issue with Unit 2 management.

b. Observations and Findings

System Description

The design bases of the GTS, according to the Unit 2 UFSAR, Section 6.5.1, include: limiting the release of radioactive gases to the environment in the event of a LOCA condition; maintaining a negative pressure in the reactor building under accident conditions; and providing redundant filter trains so that damage to one train does not cause damage to the other. These functions are accomplished by processing the air from the reactor building and/or primary containment before discharging it to the environment via the main stack. (Refer to the partial system drawing below.) The GTS consists of two redundant and physically separated divisions, each containing a filter train, a fan, and associated valving. The filter train assembly includes: a moisture separator; an electric heater to lower humidity; a prefilter; a high efficiency particulate air (HEPA) filter; a charcoal adsorber to remove radioactive iodine and particulates; and a second HEPA filter.



Unit 2 Standby Gas Treatment System

Decay heat is generated as a result of radioisotope retention in the charcoal portion of the filter train. In a post-accident scenario, when both trains automatically initiate, Operating Procedure N2-OP-61B, "Standby Gas Treatment System," Revision 7, allows one train to be secured. If the temperature in the charcoal

adsorber portion of the standby filter train exceeds 200 degrees Fahrenheit (°F), N2-OP-61B directs the operator to open the decay heat removal valve (2GTS*MOV4A/B) associated with the standby train and ensure that both cross-connect valves (2GTS*MOV28A and 2GTS*MOV28B) are open. This provides a small amount of cooling flow through the standby filter. If the temperature in the charcoal adsorber portion of the operating train exceeds 300 °F, then the standby train will automatically restart to reduce the load on the operating train. In the event that decay heat causes a spontaneous ignition fire in the charcoal portion of the filter train, an internal water deluge system can be manually initiated. To prevent a fire in one train from affecting the other train, the normally open cross-connect valves are designed to automatically close if the temperature downstream of the cross-connect valves exceeds 240 °F (as sensed by 2GTS*TIS29A/B), indicating a possible fire in the filter train.

Discussion

The Division II cross-connect valve (MOV28B) had been failed open since October 9, 1995, due to a faulty electro-hydraulic valve actuator. On December 10, 1996, with Unit 2 at full power, the Division I cross-connect valve (MOV28A) was deenergized in the open position and declared inoperable in preparation for calibration of the associated downstream temperature indicating switch (TIS29A). At that time, the SSS log noted that redundant decay heat removal capability was available from the water deluge system. After the calibration was completed, operators clearing the markup noted problems with the valve actuator of MOV28A.

On December 13, 1996, during system restoration, a Unit 2 system engineer initiated DER 2-96-3351, documenting a concern that the system may have been operated in a condition that was beyond the design basis as described in the UFSAR. Specifically, the engineer noted that both GTS cross-connect valves were failed in the open position at the same time and may have prevented the system from maintaining physical separation of the trains in the event of damage to one train. Following repairs, MOV28A and MOV28B were returned to service on December 13, 1996 and January 24, 1997, respectively.

NRC Regulatory Guide (RG) 1.52, Revision 2, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Section C.2.b, states that trains should be physically separated such that damage to one train does not also cause damage to the redundant train. In Section 1.8 of the Unit 2 UFSAR, NMPC committed to complying with the requirements of RG 1.52. On January 15, 1997, during the DER disposition process, NMPC determined that the GTS was unable to fulfill its intended safety function during the period when both cross-connect valves were failed open. Specifically, because the ability to achieve physical separation was not maintained, the GTS would not have been able to control the release of radioactive material. The licensee reported the condition to the NRC, as required by 10 CFR 50.72. A subsequent engineering operability

analysis determined that the GTS had always been operable; subsequently, the event notification was retracted on February 10, 1997.

Per N2-OP-61B, the normal GTS lineup requires both cross-connect valves to be open. The Unit 2 TS, Section 3.6.5.3, requires two independent GTS subsystems to be operable in Condition 1 (reactor at power). The inspectors questioned NMPC as to whether the retraction was appropriate and, generically, whether operation with both valves normally open satisfied the requirements of TS Section 3.6.5.3. In addition, the inspectors questioned the why a 50.59 safety evaluation was not performed for the extended inoperable condition of MOV28B. Pending further review by the NRC, this item will remain unresolved. **(URI 50-410/97-01-01)**

The inspectors identified that the UFSAR, Figure 6.5-1, sheet 8 of 8, states that MOV28A(B) de-energize to close. However, the valves were modified in 1988 to open when de-energized. The associated safety evaluation (SE 88-047, Revision 2) and licensing design change notice (LDCN U-343, Revision 2) noted that the specific figure in the UFSAR was affected by this modification, but apparently the change to update the UFSAR was never submitted to the NRC. This is a violation of 10 CFR 50.71(e), which requires each licensee to submit to the NRC periodic updates of the UFSAR, including all changes made to the facility as described in the UFSAR. This NRC-identified failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy.

c. <u>Conclusions</u>

Inadequate attention to plant equipment status and system configuration allowed both GTS cross-connect valves to be failed open and jeopardize the operability of both system trains. Specifically, poor oversight by operations and maintenance management accepted the "B" cross-connect valve to be inoperable for fourteen months, and inadequate work planning permitted the "A" cross-connect valve to be placed in an inoperable condition at the same time. In addition, the inspectors identified a plant design change made during initial operation which was not properly reflected in the Unit 2 UFSAR (NCV).

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment (37551, 40500)

E2.1 <u>Unit 1 RBCLC Pipe Supports Outside Design Basis</u>

On February 6, 1997, NMPC notified the NRC that some pipe supports inside containment for the Unit 1 reactor building closed loop cooling (RBCLC) water system were outside of the design basis, as described in the UFSAR. Specifically, the supports could exceed allowable stresses for a design basis seismic event. However, based on an engineering calculation, the licensee determined that the

supports were operable, in that they met the stress requirements of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix F.

The inspectors discussed with the Unit 1 Technical Support and Design Engineering branch managers the basis for maintaining the supports operable even though they were outside of design basis. The justification was reviewed by NRC inspectors from the regional office who confirmed that the basis was acceptable and substantiated by NRC Generic Letter (GL) 91-18, which references NRC Inspection Manual Part 9900, Technical Guidance for Operability. Section 6.13 of GL 91-18 discusses pipe supports: "... Upon discovery of a nonconformance with piping and pipe supports, licensees may use the criteria in Appendix F of Section III of the ASME Code for operability determinations. These criteria and use of Appendix F are valid until the next refueling outage, when the support(s) are to be restored to the FSAR [Final Safety Analysis Report] criteria." The supports are scheduled to be repaired during the refueling outage planned to start on March 3, 1997.

E2.2 <u>(Update) URI 50-410/96-14-01: Hot Shorts Vulnerability of Unit 2 MOVs Controlled from the Remote Shutdown Panel</u>

a. <u>Inspection Scope</u>

NMPC identified that Unit 2 was potentially outside the design basis for alternate safe shutdown for a postulated fire in the main control room. In particular, a "hot short" condition could have caused MOVs in the reactor core isolation cooling (RCIC) system to be driven closed and mechanically damaged, preventing remote shutdown capability. A hot short is an undesigned electrical connection in the system's circuitry to other than ground potential. The inspectors reviewed the applicable DERs, Licensee Event Report (LER), plant procedures, licensee's safety evaluation, NRC Information Notice 92-18, "Potential for Loss of Remote Shutdown Capability during a Control Room Fire," and portions of the UFSAR, TS and Safety Evaluation Report (SER). Additionally, the inspectors discussed the issue with Unit 2 plant management, design engineering and operations staff.

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

In December 1996, NMPC identified several MOVs that were susceptible to mechanical damage if the hot short bypassed the torque switch, causing spurious operation and a valve stall condition. The concern was applicable to MOVs controlled from the remote shutdown panel (RSP) during a control room fire. The issue was initially described in NRC IR 50-410/96-14, Section E2.1, as an unresolved item. Included in the list of MOVs subject to damage were several RCIC system valves. However, because a procedure previously existed, the licensee incorrectly assumed, at that time, that there was adequate redundancy for the RCIC system to accomplish safe-shutdown from the RSP.

On January 14, 1997, during the Station Operations Review Committee (SORC) review of fire-induced hot shorts in MOVs in the residual heat removal system (RHR), the SORC identified that susceptible MOVs within the RCIC system may not

have adequate redundancy. The licensee initiated an evaluation to determine whether the plant was outside the design basis. Although the physical design of the plant had the capability to achieve safe-shutdown from the RSP with RCIC unavailable, the method to accomplish this had not been analyzed, nor had operating procedures been established. This lack of procedures was documented in DER 2-95-2065, dated June 29, 1995. The inspectors consider it a weakness that NMPC failed to recognize that the RCIC system did not have adequate redundancy upon determining MOV susceptibility; especially considering the fact that a DER already existed documenting the lack of a procedure to accomplish the alternate means of safe-shutdown from the RSP.

The method to achieve safe-shutdown from the RSP with RCIC unavailable is described as a "pseudo low pressure coolant injection (LPCI)." Pseudo-LPCI requires depressurizing the reactor coolant system from the RSP, via four safety relief valves, to allow LPCI to inject. A RHR pump would take a suction from the suppression pool and pump water into the reactor vessel using the normal shutdown cooling return lines. However, an evaluation to determine the acceptability of pseudo-LPCI needed to be accomplished. Also, the necessary steps to accomplish pseudo-LPCI needed to be proceduralized.

On the morning of January 15, the inspectors expressed concern to the Unit 2 Operations Manager regarding RCIC system operability with respect to achieving safe-shutdown during a control room fire. The Operations Manager believed the system was operable based on successfully completed surveillance tests; however, the licensee was still evaluating the design basis of the plant with respect to alternate safe-shutdown. Subsequently, this concern was documented in DER 2-97-0118. In the evening of January 15, NMPC declared the RCIC system inoperable from the RSP in accordance with TS 3.3.7.4. NMPC notified the NRC, in accordance with 10 CFR 50.72, that the plant was potentially in a condition outside the design basis.

On January 22, NMPC determined pseudo-LPCI to be an acceptable method to achieve safe-shutdown, as documented in Safety Evaluation 97-027. In addition, Procedures N2-OP-78, "Remote Shutdown System" and N2-SOP-78, "Control Room Evacuation," were revised, incorporating the necessary steps to accomplish pseudo-LPCI. The RSP was returned to an operable status later that day.

The inspectors reviewed the safety evaluation and the procedure revisions, and determined them to be appropriate. The inspectors verified, through discussions with the Unit 2 Operations Manager, that the procedures were validated, and that appropriate training was provided to the operators. The additional concerns related to the RCIC system identified in this report will be included in URI 96-14-01. The original item remains unresolved pending the completion of the licensee's analysis to determine whether Unit 2 was in a condition outside the design basis, and subsequent NRC review.

c. Conclusions

Upon determining that RCIC system MOVs susceptible to mechanical damage during a fire-induced hot short did not have adequate redundancy, NMPC took appropriate actions. However, the failure to confirm that the RCIC system had adequate redundancy is indicative of a weak review process, particularly since a DER already existed documenting the lack of a procedure for accomplishing the alternate method of safe-shutdown.

E2.3 (Update) URI 50-220 & 50-410/96-14-02: Potential Overpressurization Concerns Relative to NRC GL 96-06

a. Inspection Scope

In December 1995, NMPC identified several primary containment penetrations at both units that could be overpressurized during a design-basis LOCA. These concerns were described in NRC IR 50-220 & 50-410/96-14, and were being tracked as an URI. During this inspection period, NMPC identified additional pipe segments that could be overpressurized during a design-basis LOCA.

To determine the adequacy of the licensee's immediate corrective actions, the inspectors reviewed the applicable DERs, engineering supporting analyses, and NRC GL 96-06, "Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions." Additionally, the concerns were discussed with NMPC engineering and operations personnel.

b. Observations and Findings

NMPC identified several additional piping segments that could potentially be overpressurized due to thermal expansion of entrapped fluid during a design-basis LOCA. The new potential overpressure conditions are:

- core spray discharge line penetrations (Unit 1),
- double-valved vent, drain and test connections on water-filled systems inside primary containment (Units 1 and 2),
- reactor water cleanup (RWCU) pump suction line penetration (Unit 2), and
- reactor recirculation flow control valve (FCV) hydraulic oil line penetrations (Unit 2).

In each case, NMPC considered the systems to be potentially outside their design basis and notified the NRC in accordance with 10 CFR 50.72. The inspectors reviewed the engineering supporting analyses for each case, and deemed the bases for operability to be consistent with guidance provided in GL 96-06.

NMPC identified two potential overpressure situations that were not readily apparent from the guidance provided in the GL. First, the fluid trapped in the Unit 2 reactor recirculation FCV penetrations was hydraulic oil and not water. Second, the condition identified on the Unit 2 RWCU system could only occur during an

abnormal plant condition when the system had been idle for an extended period. The inspectors considered the identification of these concerns to be examples of a good questioning attitude.

The additional potential overpressurization examples identified during this inspection period will be included in URI 96-14-02. This item remains unresolved pending the completion of NMPC's evaluation to confirm that these conditions were outside the design basis and subsequent NRC review.

c. Conclusions

NMPC identified several piping segments at both units that could potentially be overpressurized during a design-basis LOCA. In each case, the operability determination was adequate and consistent with the guidance provided in GL 96-06. NMPC demonstrated a good questioning attitude by identifying potential overpressure concerns resulting from situations not readily apparent from the guidance provided in the GL.

E7 Quality Assurance in Engineering Activities

E7.1 Differing Conclusions Between an NRC Inspection and NMPC Audit of C&D Battery Vendor

On December 17, 1996, the NRC Special Inspection Branch issued a report for an inspection at C&D Charter Power Systems, Inc. (C&D) facilities located in Attica, Indiana and Conshohocken, Pennsylvania (see NRC IR No. 99901304/96-01). C&D supplied lead-acid storage batteries to NMPC for safety-related applications. The NRC staff review of the inspection report identified several concerns:

- The NRC inspection discovered problems in C&D's implementation of its quality assurance (QA) program related to the dedication of battery cells after manufacture. The NRC concluded that the vendor did not have an adequate dedication program or a basis for dedication for their products.

- The NRC noted that NMPC had last audited C&D in August of 1994; however, that audit did not identify the commercial grade dedication program implementation problems that NRC found. The disparity between the NRC's and the licensee's findings suggested a possible problem with the effectiveness of NMPC's audit process as implemented at the C&D facility.

- In addition, disparity in the findings suggested the need for a thorough operability determination to confirm that any C&D batteries installed in Class 1E applications at Nine Mile Point remained functional and that any degraded condition be identified and resolved in a timely manner, consistent with 10 CFR 50 Appendix B, Criterion XVI.

The significance of the disparity in results between the NMPC audit and the NRC inspection related to C&D remains an unresolved item pending NRC assessment of

the licensee review of the issue, necessary corrective actions, and a review of the extent of condition of any problems found. (URI 50-220 & 50-410/97-01-02)

The effect of C&D's commercial dedication program on the operability of any C&D batteries supplied for Class 1E service is also an unresolved item. (URI 50-220 & 50-410/97-01-03)

The licensee initially stated that the only C&D batteries in use at Nine Mile were at Unit 1. Subsequently, the NMPC QA Manager informed the inspectors that at least one additional use of C&D batteries was at Unit 2, for the HPCS system. Pending further NRC review of NMPC's ability to identify the location and use of purchased equipment, this will remain an unresolved item. (URI 50-220 & 50-410/97-01-04)

E8 Miscellaneous Engineering Issues (90712, 92700, 92903)

E8.1 <u>(Closed) LER 50-220/96-12: Missed Local Leak Rate Tests Caused by Personnel Error</u>

On November 8, 1996, during maintenance on Unit 1 containment vacuum relief breaker 68-02, grease was discovered in the local leak rate test (LLRT) port for the shaft sleeve seal. During valve disassembly; the licensee also identified untested LLRT ports on the stuffing box seals. On November 10, the licensee determined that the stuffing box seals had never been Type B leak rate tested, as required by TSs, and that the grease in the shaft sleeve for valve 68-02 may have invalidated previous Type B tests. Further licensee investigation identified six additional containment vacuum relief breakers with grease in the shaft sleeve seal LLRT ports.

The system engineer informed the inspectors that the seals were modified in 1983, and no longer required grease. Subsequently, the grease fittings were modified to function as LLRT ports for the Appendix J program. The licensee determined the apparent root cause to be personnel error; in that: (1) the LLRT ports were inappropriately used to grease the seals, and (2) self-checking was ineffective to ensure that the seals had been included in the Appendix J program.

NMPC Unit 1 TS Surveillance Requirement, Section 3.3.3.d, requires primary containment testable penetrations and isolation valves to be Type B or Type C tested at a pressure of 35 pounds per square inch gage each refueling outage, not to exceed two years. Since 1983, NMPC failed to conduct LLRTs on containment vacuum relief breaker seals. The failure to include the containment vacuum relief breaker LLRT ports in the Appendix J program is a violation of TS Surveillance Requirements. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

However, the licensee had satisfactorily completed four integrated leak rate tests during which the containment vacuum relief breaker shaft seals and stuffing box seals were subjected to test pressure. In addition, the inspectors verified that the vacuum breakers were operable the entire time with respect to being able to perform their intended safety function by means of satisfactory monthly surveillance

tests. The inspectors reviewed the LER and determined it satisfactorily described the issue. The root cause evaluation, and immediate and followup corrective actions to prevent recurrence appeared appropriate.

E8.2 (Closed) LER 50-220/96-13 and LER 50-410/96-16: Potential Overpressurization of Containment Penetrations due to Thermal Expansion

The inspectors described the technical details associated with these LERs in NRC IR 50-410/96-14, Section E2.2. The inspectors considered the LERs to be timely and to accurately describe the event and root cause of the event, and the immediate corrective actions appeared adequate. The long term corrective actions will be included in the licensee's response to GL 96-06.

E8.3 (Closed) LER 50-410/96-13: Technical Specification Violation Caused by Inadequate Change Management (Both Trains of Service Water Inoperable)

On November 5, 1996, the licensee determined that both divisions of the service water system had been inoperable for several hours in October 1996, during the recent Unit 2 refueling outage. Specifically, both isolation valves for the non-essential header (2SWP*MOV93A/B) of the service water system were open, while the automatic closure logic for the MOV93B was defeated. An operator noticed that both valves were open and informed the SSS; one of the valves was closed and placed under administrative control. The licensee determined the cause to be an inadequate assessment of schedule changes during the outage. The inspectors reviewed the LER and determined that it accurately described the event. The root cause analysis, immediate corrective actions, and corrective actions to prevent recurrence appeared adequate.

However, both trains of service water being inoperable is a violation of the Unit 2 TS, Section 3.7.1.2, "Plant Service Water System - Shutdown." This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

E8.4 (Open) LER 50-410/96-15: Appendix R Fire Induced Hot Shorts in Remote Shutdown System Valves

The inspectors reviewed the LER which described two instances where fire-induced hot shorts could render valves unable to perform their intended 10 CFR 50, Appendix R, cold shutdown function during a postulated control room fire. The first instance pertained to three valves within the RHR system, and was described in NRC IR 50-410/96-14. The second instance pertained to valves within the RCIC system, and was described in Section E2.2 of this report. The LER satisfactorily described the events. The immediate corrective actions were adequate to address the concerns. The licensee had not yet been able to determine why the potential valve damage effects were not addressed by the original safe shutdown analysis. In the LER, NMPC committed to complete a root cause evaluation with further corrective actions, and to submit a supplement. Therefore, the LER remains open

pending submittal of the LER Supplement and subsequent NRC review of the root cause and long term corrective actions.

E8.5 (Closed) LERs 50-220/96-08, 50-220/96-08-01, 50-410/96-12 and 50-410/96-12-01: Violation Involving Missed Augmented Inspection Caused by Inadequate Change Management

The technical details associated with these LERs were described in Section E1.1 of NRC IR 96-13 and associated violation 96-13-03. LERs 50-220/96-08 and 50-410/96-12 were reviewed in the same report, but were left open because the licensee had not yet determined the root cause, nor had they completed their review of other suspect systems. As described in the LER supplements, the root cause was inadequate change management, which the inspectors determined to be appropriate; in addition, the corrective actions was determined to be adequate. Also, as described in the Unit 1 LER supplement, NMPC noted additional weld inspections that were missed for the Unit 1 reactor recirculation system, the details of which were also described in IR 50-220/96-13.

E8.6 (Closed) 10 CFR Part 21: Unit 1 Premature Failure of Containment Monitoring System Pump Diaphragms

a. Inspection Scope

Teledyne Brown Engineering Analytical Instruments (TBE/AI) issued a 10 CFR Part 21 (Part 21) report regarding premature failure of containment monitoring system (CMS) pump diaphragms. The inspectors assessed the licensee's actions taken to address this concern by evaluating applicable correspondence between the licensee and TBE/AI, DERs, and special reports. Additionally, the inspectors discussed the issue with the system engineer.

b. Observations and Findings

In July 1995, Unit 1 experienced a premature failure of #11 CMS analysis pump diaphragm. This failure caused system in-leakage, resulting in erroneous containment hydrogen and oxygen measurements. Subsequently, the diaphragm was replaced and the system was returned to an operable status. On September 13, 1995, #12 CMS analysis pump and bypass pump diaphragms were inspected and replaced. To evaluate diaphragm performance, NMPC replaced the #11 CMS analysis pump and bypass pump diaphragms on October 19, 1995. The licensee found rough edges on the diaphragm plates that corresponded with worn areas on the diaphragms. NMPC polished the diaphragm plates before returning the system to an operable status.

In October 1995, NMPC contacted TBE/AI regarding the problems experienced with the CMS (Model 225 CMA-X) pump diaphragms (TBE/AI Part Number D162). TBE/AI recommended that NMPC replace the existing diaphragms with new diaphragms made of different material. TBE/AI also provided new torque specifications to prevent diaphragm over-torquing, and informed NMPC that the

rough edges on the diaphragm plates would not have contributed to the premature failure of the diaphragms. Based on the information provided, TBE/AI filed a Part 21 report on October 31, 1995, and stated that recommendations would be sent to all United States customers per the Part 21 requirements.

Prior to the scheduled implementation of TBE/AI's recommendations, #12 CMS analysis pump diaphragm failed. NMPC documented the CMS failure in DER 1-96-0022, and used this DER to track the completion of TBE/AI's recommendations. On January 17, 1996, the #12 CMS analysis pump and bypass pump diaphragms were replaced with the new-material diaphragms. In addition, NMPC polished the diaphragm plates. NMPC noted that the as-found torque values were significantly lower than those recently recommended. The licensee completed the diaphragm replacement on #11 CMS on March 1, 1996. The parts list was updated to incorporate the new part numbers, and the vendor manual and maintenance procedures were changed to incorporate the new torque values. Since replacement of the pump diaphragms, no similar failures have occurred at Unit 1.

c. Conclusions

Licensee actions to correct the repetitive and premature failure of containment monitoring system pump diaphragms were appropriate and resulted in a Part 21 report being written by the vendor.

E8.7 (Closed) 10 CFR Part 21: Unit 2 Clow Valve Stub Shaft Dowel Pin Failure

a. Inspection Scope

NMPC notified the NRC of a manufacturing defect associated with valves manufactured by Clow Corporation. The inspectors reviewed the Part 21 notification, applicable DERs, engineering supporting analyses, procedures and work orders. Additionally, the inspectors discussed the issue with the responsible design engineer, the Independent Safety Engineering Group (ISEG), and members of the licensing department.

b. Observations and Findings

On April 22, 1996, while Division II GTS was inoperable for preplanned work, maintenance personnel discovered that the dowel pin, holding the stub shaft to the main shaft for the GTS discharge valve 2GTS*MOV3B, fell out of position. The details associated with this failure were described in NRC IR 50-410/96-06.

Unit 2 design engineering determined that the cause of the dowel pin failure was a manufacturing deficiency to properly peen the pin in place. However, they concluded that the missing dowel pin did not constitute a "substantial safety hazard," since the valve would still open and close properly; therefore, the failure did not require a Part 21 review. The results of the engineering evaluation were included in DER 2-96-1058, dispositioned on May 23, 1996.

During a review of DER 2-96-1058, a Unit 2 ISEG engineer determined that the dowel pin failure did require a Part 21 evaluation. ISEG based this on the function of the GTS discharge valve stub shaft, which is to operate limit switches in the GTS fan start circuitry. Thus, although the valve would open, the GTS fan would not have started. Therefore, the missing dowel pin did constitute a "substantial safety hazard." NMPC documented the inadequate Part 21 determination in DER 2-96-1629. On July 23, 1996, NMPC notified the NRC, in accordance with Part 21, of a manufacturing defect associated with the valves.

The inspectors reviewed the Part 21 notification, which included the required information. The corrective actions described in the letter included verifying proper peening of the dowel pin for other valves with a similar limit switch function. Although there are other valves manufactured by Clow Corporation at Unit 2, only the two GTS discharge valves have the potential to make the system inoperable due to a failure of the stub shaft to reposition. Proper peening of the Division I GTS discharge valve was verified through WO 96-11069-00.

The inspectors reviewed DER 2-96-1629, pertaining to the inadequate Part 21 determination, and noted that the root cause was a failure to recognize the unique function of the discharge valve limit switches. Additionally, corrective action included counselling of the individuals involved, and enhancements to the DER procedure to provide clearer direction for Part 21 evaluations. The inspectors reviewed the procedures applicable to completing Part 21 reviews. The inspectors reviewed the applicable procedures that address the initial screening for potential Part 21 concerns. The detail provided in Procedures NIP-ECA-01, "Deviation/Event Report," Revision 01, and NIP-IRG-01, "Interface with the NRC," Revision 08, was weak and could result in a failure to recognize potential Part 21 issues. This weakness was evidenced by the inadequate Part 21 determination initially performed on the improperly peened dowel pin. The proposed enhancements to the DER procedure, as described in DER 2-96-1629, appeared to appropriately address this weakness. Once identified as a Part 21 concern, the issue is referred to the NMPC licensing department for review, in accordance with Procedure NLAP-IRG-140, "Notification Under 10 CFR 21," Revision 01. The inspectors considered NLAP-IRG-140 to contain sufficient detail for completion of Part 21 determinations.

c. <u>Conclusions</u>

The ISEG identification of the inadequate 10 CFR Part 21 determination pertaining to the improperly peened dowel pin in the GTS discharge valve was very good. However, the detail in the DER procedure regarding Part 21 initial screening was weak and would have resulted in a failure of a Part 21 concern to receive timely review, if not for identification by ISEG. Once identified, the licensee took appropriate actions to complete the Part 21 notification, and verified that no other suspect valves were affected.

E8.8 (Closed) Special Report: #11 Containment Monitoring System Inoperable

On January 14, 1997, with Unit 1 operating at 100% reactor power, NMPC declared the #11 CMS inoperable for preventive maintenance and routine calibration. It was returned to service on January 29. The redundant system (#12 CMS) was inoperable from January 20 through January 23 because of erratic readings due to a poorly soldered connection. During the period when both systems were inoperable, the licensee met TS 3.6.11-1, Action Statement Table 3.6.11-2(4b) requirements.

The preventive maintenance on #11 CMS included diaphragm replacement on the sample and bypass pumps. The licensee stated that pump diaphragm replacement was a pre-planned preventive maintenance action recommended by the vendor, and previously described in Section E8.6 of this report. The diaphragms on #12 CMS were to be replaced during the next scheduled preventive maintenance.

NMPC submitted this special report to the NRC within 14 days, as required by Unit 1 TS 3.6.11-1, Action Statement Table 3.6.11-2 (4a). The inspectors reviewed the special report and confirmed that all required information was provided.

E8.9 (Closed) Special Report: #12 Drywell High Range Gamma Radiation Monitoring System Inoperable

On January 15, 1997, with Unit 1 operating at 100% reactor power, NMPC declared the #12 drywell high range gamma radiation monitoring system inoperable due to erratic indication. During the period when #12 drywell high range gamma radiation monitoring system was out of service, the redundant system remained operable. The licensee stated the apparent root cause for the current system inoperability was aged components in the power supply, and that repairs will be made during the refueling outage in March 1997.

NMPC submitted this special report to the NRC within 14 days, as required by Unit 1 TS 3.6.11-1, Action Statement Table 3.6.11-2 (3a). The inspectors reviewed the special report and confirmed that all required information was provided.

E8.10 (Closed) URI 50-410/94-32-01: Incorrect Fuses Installed in the Reactor Protection System

a. Inspection Scope

URI 50-410/94-32-01 pertained to incorrect fuses installed in the Unit 2 reactor protection system (RPS) and questioned the adequacy of the Unit 2 fuse control program. This URI was updated in NRC IR 50-410/95-23, pending additional review. The inspectors reviewed the history associated with this issue, including applicable plant drawings, procedures and DERs. The inspectors also discussed the issue with the system engineers and the Unit 2 Technical Support Manager.

b. Observations and Findings

In January 1995, while performing maintenance on the RPS, the licensee identified that three installed fuses were inconsistent with the fuse list and/or system drawings. Actions were taken to install the correct fuses, and DER 2-95-0154 was initiated to document the event. The licensee performed an engineering supporting analysis to evaluate the impact of the incorrect fuses and determined that there was no adverse affect on RPS operability. Additionally, the licensee stated in the DER that a sample of installed RPS-related fuses would be reviewed for agreement with design documentation to assess the extent of the problem.

As documented in NRC IR 50-410/95-23, the inspectors reviewed the engineering supporting analysis and the maintenance procedure for fuse replacement, and determined that they provided adequate instruction. However, the inspectors were concerned that there was no documented justification for the small sample size used to determine the adequacy of the fuse control program. During the current inspection period, a review of the Unit 2 controlled fuse list (Drawing AE-001, "PGCC Fuse List") revealed that approximately 150 fuses were installed in the RPS. Without proper justification, the inspectors consider a sample of 8 RPS fuses (approximately 5%) to be too small to adequately assess the extent of the problem. Although there is no requirement to justify the small size, this indicates a weakness in the corrective action program.

Also, during this period, the inspectors reviewed WO 95-0175-00, used to perform the verification sample of installed fuses, and noted that the licensee identified no inconsistencies with installed RPS fuses. However, during the fuse verification, NMPC did identify that one of the other fuses sampled, for the feedwater control system, was listed incorrectly on the fuse list. NMPC corrected the fuse list; but the inspectors identified that no actions were taken to determine the root cause. Subsequently, NMPC determined that the originally installed fuse was changed by an engineering design change (EDC), but the EDC indicated that the fuse list was not impacted by the change. NMPC wrote DER 2-97-0430 for failure to initiate a DER in 1995, when the fuse list discrepancy was identified. The failure to initiate a DER was not in accordance with Procedure NIP-ECA-01, "Deviation Event Report," Revision 8, and was a violation of Unit 2 TS 6.8.1, which requires procedures to be implemented. This failure constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

In December 1995, NMPC initiated DER 2-95-3298 to collate the history of fuse-related problems at Unit 2. The inspectors reviewed the DER, which documented that twelve cases of incorrect fuses, and six cases of missing fuses, were identified over the previous three years. The Unit 2 Technical Support Manager indicated that all of the cases identified were non-safety-related, and that corrective actions were taken to address each case individually. Based on no additional safety-related fuse control problems, and an acceptable fuse replacement procedure (as noted in NRC IR 95-23), the inspectors had no further concerns. However, the incorrect fuses

installed in the RPS (January 1995), and the incorrectly listed feedwater control system fuse (April 1995), are examples of a failure to maintain plant configuration in accordance with controlled drawings, as required by 10 CFR 50 Appendix B Criterion V, "Instructions, Procedures, and Drawings." This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusion

During the review of a 1994 unresolved item pertaining to incorrect fuses installed in the Unit 2 RPS, the inspectors determined licensee performance to be weak; in that, without proper justification, a sample size of 5% was too small to adequately assess the extent of the problem. Also, in 1995; when the licensee identified an additional fuse discrepancy, it was not addressed by the DER process, as required by procedure, and resulted in a failure to determine a root cause (NCV). The failure to ensure that the installed fuse configuration was consistent with controlled drawings was a violation of 10 CFR 50, Appendix B, Criterion V (NCV). The inspectors considered the fuse control program adequate based on a procedure review and no additional safety-related fuse inconsistencies identified.

IV. PLANT SUPPORT

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

R2 Status of Radiological Protection & Chemistry (RP&C) Facilities and Equipment (71750)

R2.1 Tour of Unit 2 Radiological Waste Facility

On February 7, 1997, the inspectors toured the Unit 2 radiological waste facility with the Radiological Waste Supervisor. General housekeeping and material storage within the facility were good. Flammable liquids stored within the facility, pending chemical processing, had been appropriately evaluated in accordance with the licensee's fire protection program. No discrepancies were identified.

R8 Miscellaneous RP&C Issues (90712)

R8.1 (Closed) Special Report: Unit 2 Meteorological Monitoring Instrumentation Inoperable

On November 22, 1996, NMPC identified that there was a discrepancy between the actual elevation of the meteorological monitoring instrumentation for the Nine Mile site and the location described in the Unit 2 UFSAR and the Unit 2 TS. At that

time, the air temperature instruments were declared inoperable; subsequently, on December 5, the wind speed and direction instruments were also considered inoperable. The basis for the meteorological instrumentation is to ensure that sufficient data is available for estimating potential radiological doses to the public as a result of a planned or accidental release to the environment. This information would be used to evaluate the need for initiating protective measure recommendations for the public. Although technically inoperable, the effect of the difference in height is negligible; as such, the instrumentation would be available, if needed. The required and actual locations are listed below:

Unit 2	TS 3.3.7.3	UFSAR 2.3	Actual
Air temperature instruments	30 ft	27 ft	26.8 ft
	200 ft	200 ft	194.8 ft
Wind speed & wind direction instruments	30 ft	30 ft	30.9 ft
	200 ft	200 ft	199.4 ft

If any meteorological instrument is inoperable for more than seven days, the Unit 2 TS, Section 3.3.7.3, requires submittal of a special report to the NRC within the following ten days; the special report was submitted on December 9, 1996. The licensee verified by field survey that the instrument locations have probably not been as described in the Unit 2 UFSAR and TSs since initial installation.

R8.2 (Closed) LER 50-410/96-14: Failure to Submit a Special Report Concerning Inoperable Meteorological Instrumentation

This LER describes the event discussed in the preceding section. The inspectors reviewed the LER and determined that it satisfactorily described the event, the root cause evaluation, and planned corrective actions to prevent similar occurrences in the future. NMPC intends to correct the location of the meteorological instrumentation when they submit the Improved Technical Specifications for review by the NRC.

The meteorological instruments have been inoperable since initial installation, and a special report should have been submitted at that time. However, since the special report was not submitted, Unit 2 had been operating in a condition outside the TSs. This licensee-identified finding constitutes a violation of minor significance and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Status of Fire Protection Equipment

During routine inspections of both units, the inspectors noted that fire protection equipment appeared to be maintained in good condition. Fire extinguishers and hose stations were inspected at the required frequency and no physical deterioration

was noted. Fire break zones were maintained free of combustible material. In addition, housekeeping was consistent with the level of activity in the surrounding area, and general work area cleanliness appeared to be maintained.

The inspectors considered that licensee efforts to maintain fire suppression equipment and plant areas in a condition to support fire prevention, detection, and suppression to be good.

F3 Fire Protection Procedures and Documentation

F3.1 Markup of Halon Fire Suppression System at Unit 2

During a tour of the Unit 2 Control Building, the inspectors noted that one of the two halon tanks for fire suppression in the control room had been removed for refilling on November 18, 1996. In reviewing the markup for isolation of the removed tank (TK3A), the inspectors identified that a single check valve was being used for isolation of the system to the surrounding atmosphere. The inspectors had two concerns related to the potential for the check valve to leak, and discussed the concerns with the SSS. The concerns were: (1) upon actuation of the system, the halon could escape to the immediate area and present a hazardous environment for personnel; and (2) if the halon leaked to the surrounding area, the concentration of halon needed for fire suppression in the control room would be reduced. The SSS contacted the fire protection department who immediately capped the flexible hose and initiated DER 2-96-3159.

The NMPC fire protection system engineer determined that the markup procedure did not preclude the use of a check valve as an isolation point. In addition, the National Fire Protection Association standard for halon fire extinguishing systems (Section 12A) only required an automatic means to prevent agent loss from the manifold if the system was operated when any containers were removed for maintenance. The licensee position was that the installed check valve met the requirements for automatic isolation. The licensee is evaluating a change to the fire protection procedures to require the use of caps as added isolation for the halon system and other similar applications.

The inspectors considered the immediate action to cap the flexible hose a prudent act while NMPC dispositioned the DER. Although no violation of procedural requirements existed, the inspectors considered the existing system markup procedure to be weak; specifically, the procedure did not preclude the use of a single check valve as personnel protection from hazardous conditions. The inspectors had no further questions.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The final exit meeting occurred on March 14, 1997. Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

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

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 60705:	Preparation for Refueling
IP 60710:	Refueling Activities
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 90712:	In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND UPDATED

OPENED		
50-410/97-01-01	URI	Unit 2 Standby Gas Treatment System Operability with Both Cross-Connect Valves Open
50-220 & 50-410/97-01-02	URI	Disparity in NMPC Audit and NRC Inspection Findings of C&D Charter Power Systems, Inc.
50-220 & 50-410/97-01-03	URI	C&D Charter Power Systems, Inc. Dedication Program and Operability of Class 1E Batteries
50-220 & 50-410/97-01-04	URI	Ability of NMPC to Identify the Location and Use of Purchased Equipment
50-410/96-15	LER	Appendix R Fire Induced Hot Shorts in Remote Shutdown System Valves
CLOSED		
50-220/96-12	LER	Missed Local Leak Rate Tests Caused by Personnel Error
50-220/96-13	LER	Potential Overpressurization of Containment Penetrations due to Thermal Expansion
50-410/96-13	LER	Technical Specification Violation Caused by Inadequate Change Management (Both Trains of Service Water Inoperable)
50-410/96-16	LER	Potential Overpressurization of Containment Penetrations due to Thermal Expansion
50-220/96-08	LER	Violation Involving Missed Augmented Inspection Caused by Inadequate Management
50-220/96-08-01	LER	Violation Involving Missed Augmented Inspection Caused by Inadequate Management
50-410/96-12	LER	Violation Involving Missed Augmented Inspection Caused by Inadequate Management
50-410/96-12-01	LER	Violation Involving Missed Augmented Inspection Caused by Inadequate Management
---	10CFR21	Unit 1 Premature Failure of Containment Monitoring System Pump Diaphragms
---	10CFR21	Unit 2 Clow Valve Stub Shaft Dowel Pin Failure
50-410/94-32-01	URI	Incorrect Fuses Installed in the Reactor Protection System
50-410/96-14	LER	Failure to Submit a Special Report Concerning Inoperable Meteorological Instrumentation
UPDATED		
50-410/96-14-01	URI	Hot Shorts Vulnerability of Unit 2 MOVs Controlled from the Remote Shutdown Panel
50-220 & 50-410/96-14-02	URI	Potential Overpressurization Concerns Relative to NRC Generic Letter 96-06

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
C&D	C&D Charter Power Systems, Inc.
CFR	Code of Federal Regulations
CMS	Containment Monitoring System
CST	Condensate Storage Tank
DER	Deviation/Event Report
DWFD	Drywell Floor Drains
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FCV	Flow Control Valve
FME	Foreign Material Exclusion
GE	General Electric
GL	Generic Letter
GTS	Standby Gas Treatment System
HEPA	High Efficiency Particulate Air
HPCS	High Pressure Core Spray
IR	Inspection Report
ISEG	Independent Safety Engineering Group
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LCO	Limiting Condition of Operation
LOCA	Loss-of-Coolant Accident
LPCI	Low Pressure Coolant Injection
M&TE	Measuring and Test Equipment
MOV	Motor-Operated Valve
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission
OSV	Operational Safety Verification
QA	Quality Assurance
QATR	Quality Assurance Topical Report
RBCLC	Reactor Building Close Loop Cooling
RCIC	Reactor Core Isolation Cooling
RG	Regulatory Guide
RHR	Residual Heat Removal
RPS	Reactor Protection System
RSP	Remote Shutdown Panel
RWCU	Reactor Water Cleanup
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SSS	Station Shift Supervisor
TBE/AI	Teledyne Brown Engineering Analytical Instruments
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WO	Work Order