August 4, 2003

Mr. Peter E. Katz
Vice President - Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000220/2003004 AND 05000410/2003004

Dear Mr. Katz:

On June 28, 2003, the NRC completed an inspection of your Nine Mile Point Nuclear Station, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on July 11, 2003, with Mr. L. Hopkins and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents two NRC-identified and two self-revealing findings of very low safety significance (Green), one of which was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it is entered into your corrective action program, the NRC is treating this violation as non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any findings in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator Region I, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at Nine Mile Point.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year '02, and the remaining inspection activities for Nine Mile Point were completed in May 2003. The NRC will continue to monitor overall safeguards and security controls at Nine Mile Point.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the

NRC Public Document Room or from the Publically Available Records (PARS) component of NRC's document management system (ADAMS). ADAMS is accessible from the NRC web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

James M. Trapp, Chief
Projects Branch 1
Division of Reactor Projects

Docket Nos. 50-220, 50-410
License Nos. DPR-63, NPF-69

Enclosure: Inspection Report 05000220/2003004 and 05000410/2003004
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	50-220, 50-410
License Nos:	DPR-63, NPF-69
Report No:	05000220/2003004 and 05000410/2003004
Licensee	Nine Mile Point Nuclear Station, LLC (NMPNS)
Facility:	Nine Mile Point, Units 1 and 2
Location:	P. O. Box 63 Lycoming, NY 13093
Dates:	March 30, 2003 - June 28, 2003
Inspectors:	C. Caron, Physical Security Inspector (Sections 3PP2, 3PP3) A. Della Greca, Senior Reactor Inspector (Section 4OA2.4) P. Frechette, Senior Physical Security Inspector (Sections 3PP2, 3PP3) B. Fuller, Resident Inspector G. Hunegs, Senior Resident Inspector J. Jang, Senior Health Physicist (Section 2PS1) E. Knutson, Resident Inspector A. Lohmeier, Reactor Inspector (Section 1R08) J. Noggle, Senior Health Physicist (Section 2OS3) G. Smith, Senior Physical Security Inspector (Section 3PP4) H. Williams, Operations Engineer (Sections 3PP2, 3PP3)
Approved by:	James M. Trapp, Chief Projects Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000220/2003-004, 05000410/2003-004; 03/30/2003 - 06/28/2003; Nine Mile Point, Units 1 and 2; Operability Evaluations; Identification and Resolution of Problems, and Event Follow-up.

This report covered a 13-week period of inspection by resident inspectors and announced inspections by eight region-based inspectors. Four Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process," (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding for an inadequate operability determination regarding the Unit 1, 11 Feedwater Pump 2-inch minimum flow valve. The operability determination failed to adequately verify the function of the minimum flow valve. The valve subsequently failed which rendered the 11 high pressure coolant injection (HPCI) train inoperable on May 17, 2003.

This finding is greater than minor because it affected the Mitigating System Cornerstone objective of equipment availability, in that an inadequate operability determination led to the conclusion that 11 HPCI train was operable, when in actuality, the 2-inch minimum flow valve failed on the next demand. The finding is of very low safety significance because the finding did not represent an actual loss of safety function of a single train for greater than its Technical Specification allowed outage time. The inadequate operability determination was an example of a cross-cutting issue in human performance. (Section 1R15)

Green. The inspectors identified a finding for an inadequate operability determination regarding intermittent erratic flow indication from Unit 1 reactor recirculation pump (RRP) 12. On May 18, 2003, 12 RRP flow indication was determined to be operable when, in actuality, an intermittent problem had developed which caused the indication to be unreliable. The original operability determination did not address the effect of the condition on the reactor protection system (RPS) because it did not take into account that the RRP flow instruments provided input to the RPS. When the condition later persisted, the adverse effect on RPS was recognized, and a half scram was manually inserted.

This finding is greater than minor because it affects the Mitigating System Cornerstone objective of equipment reliability, in that if the condition which led to equipment degradation is left uncorrected or not addressed, a more significant safety concern affecting RPS could develop. The finding is of very low safety significance because there was not an actual loss of safety function of the system. The inadequate operability determination was an example of a cross-cutting issue in human performance. (Section 1R15)

Green. The inspectors identified a self-revealing finding concerning corrective actions related to the availability of the 115 kV offsite power sources. Administrative controls were not adequately implemented to assure that one 115 kV offsite power source would remain available during planned maintenance of the other offsite power source. Corrective actions implemented following a similar condition in 2001 did not prevent the problem from reoccurring during a November 2002 offsite power line maintenance activity.

The finding is greater than minor because it affects the Mitigating Systems Cornerstone objective of equipment availability in that the operability of offsite power Line 4 was not assured while Line 1 was taken out-of-service. This degraded the reliability of the offsite electrical system. The finding was determined to be of very low safety significance because the accident mitigating systems remained operable, there was no loss of electrical system safety function, and no technical specification limiting conditions for operation were exceeded. The finding was an example of a cross-cutting issue in problem identification and resolution. (Section 4OA2)

Green. The inspectors identified a self-revealing non-cited violation for failure to implement a procedure in accordance with Technical Specification 6.8.1, which resulted in a control rod drive (CRD) pump being inoperable for 25 days. The work order for post maintenance testing of the 12 CRD pump breaker did not require performance of the 12 CRD Pump surveillance, as required by the post maintenance testing administrative procedure, and the pump subsequently failed.

The finding is greater than minor because it affects the Mitigating Systems Cornerstone objective of equipment availability in that it had an actual impact of causing the CRD pump to be inoperable for greater than the Technical Specification allowed outage time. The finding is of very low safety significance because the exposure time for this condition was less than 30 days and all other mitigation capabilities described on the SDP Phase 2 worksheet were maintained. The finding was an example of a cross-cutting issue in human performance. (Section 4OA3)

B. Licensee-Identified Violations:

None

REPORT DETAILS

Summary of Plant Status

Nine Mile Point Unit 1 (Unit 1) began the inspection period shutdown for a refueling outage (RFO17). Following the outage, there were four unsuccessful attempts to restart the plant prior to the May 2, 2003 plant restart and power ascension. The first unsuccessfully plant restart, on April 16, 2003, was terminated to repair the 13 reactor feedwater pump clutch and to conduct troubleshooting of the reactor pressure regulator. A second startup attempt, on April 21, 2003, was terminated to repair a solenoid-actuated pressure relief valve that failed during a surveillance test. Problems with the 13 reactor feedwater pump clutch again required the unit to be shutdown following the third startup attempt on April 23. A fourth startup, on April 29, 2003, was terminated to address a body-to-bonnet leak on the 12 reactor recirculation pump suction isolation valve. The plant was successfully restarted on May 2, 2003 and achieved full power on May 4, 2003. On May 31, a condensate demineralizer failure resulted in an unplanned power reduction to 84 percent. Following restoration of a condensate demineralizer to service, power was restored to 100 percent later that day. On June 20, a failed moisture separator drain tank level control valve led to an unplanned power reduction to 65 percent power to facilitate repairs. The unit was returned to full power on June 22 and continued to operate there through the end of the inspection period.

Nine Mile Point Unit 2 (Unit 2) began the inspection period at 100 percent power. Power suppression testing was performed at 65 percent reactor power on May 21 to May 23 and May 31 to June 3, 2003 to determine the location of suspected leaking fuel assemblies. Reactor power was restored to 100 percent and remained there through the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns. The inspectors performed five partial system walkdowns during this inspection period.

The inspector selected the Unit 2, emergency switchgear 101 and 102 to conduct a partial system walkdown, prior to realignment of the switchgear in preparation for maintenance. The walkdown included a control room switch verification and physical inspection and verification of the switchgear. N2-OSP-LOG-W001, "Weekly Checks," was used for this review.

The inspector selected the Unit 1 core spray systems 121 and 122 to verify proper system alignment prior to plant startup from the refueling outage. The walkdown included a control room switch verification and physical inspection and verification of the system lineup. N1-OP-2, "Core Spray System," was used for this review.

The inspector selected the Unit 2 high pressure core spray system to verify proper system alignment following system maintenance. The walkdown included a control room switch verification and physical inspection and verification of the system lineup. N2-OP-33, "High Pressure Core Spray," was used for this review.

The inspector selected the Unit 1 control rod drive system due to the extensive amount of work that had been performed on the system during the refueling outage. The walkdown included a control room switch verification and physical inspection and verification of the system lineup. N1-OP-5, "Control Rod Drive System," was used for this review.

The inspectors selected the Unit 1 reactor building closed loop cooling (RBCLC) system due to previously noted system degradation and work that was conducted during the refueling outage. The walkdown focused on material condition of system components located in the drywell. The inspectors reviewed NER-1S-033, "Evaluation of the RBCLC Piping Inside Drywell During RF017" and associated DER's that were generated as a result of the walkdown. The report addressed NRC observations of the material condition of the piping, piping components and supports. Additionally, NER-1M-036, "Assessment of RBCLC Mechanical Components Inside the Drywell Under Post LOCA Ambient Temperature" was reviewed.

Complete System Walkdown. The inspector selected the Unit 2, reactor core isolation cooling system (RCIC) to conduct a complete system walkdown. The walkdown included a control room switch verification and physical inspection and verification of the RCIC system lineup. Deficiency reports, open work orders, system health reports, and equipment status log entries were reviewed. N2-OSP-ICS-M001, "RCIC System Piping Fill and Valve Lineup Verification Test," was used for this review.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors walked down accessible portions of eight fire areas described below to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers and any related compensatory measures. The condition of fire detection devices, the readiness of the sprinkler fire suppression systems and the fire doors were also inspected against industry standards. In addition, the fire protection features were inspected, including the ventilation system fire dampers, structural steel fire proofing, and electrical penetration seals. Reference material reviewed for installed features included the Updated Safety Analysis Report. The following plant areas were inspected:

Reactor Building 175 foot elevation (Unit 2)

Turbine Building 261foot elevation (Unit 2)
RCIC Room 175 foot elevation (Unit 2)
Control Building 261foot elevation (Unit 2)
Emergency Diesel Generator Building 261foot elevation (Unit 2)
Reactor Building 261 foot elevation (Unit 1)
Reactor Building 281 foot elevation (Unit 1)
Reactor Building 340 foot elevation (Unit 1)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors examined the Unit 1 reactor building corner rooms and torus room for their susceptibility to internal flooding. These rooms were selected because they interconnect through wall penetrations and floor drains, such that flooding in one room could impact the other rooms. Documents reviewed included the Final Safety Analysis Report (FSAR), Individual Plant Examination, and Individual Plant Examination for External Events.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

a. Inspection Scope

The inspector reviewed the Unit 1 Inservice Inspection (ISI) program to verify the effectiveness of activities performed during refueling outage 17 (RFO17) to monitor degradation of the reactor coolant system boundary, risk significant piping system boundaries, and reactor vessel internals. The inspector reviewed the documentation of scheduled and completed inspections to ensure that the activities were consistent with the second period of the third ten-year interval of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code Section XI IWB-2412 Program B schedule, and also to confirm that relief requests were made when appropriate. The inspector reviewed documentation of examination results and disposition of examination findings to verify that inspection findings were adequately addressed. The review included samples of ISI program non-destructive examinations (NDE) performed by Unit 1 qualified inspection personnel using ultrasonic testing (UT), magnetic testing (MT), radiographic testing (RT), dye-penetrant testing (PT), and visual testing (VT) of selected safety system components.

The inspector reviewed UT and PT inspection findings of two indications in the top closure head meridional weld (RV-WD-005) that exceeded the allowable dimensions of ASME Section XI Table IWB-3510. The inspector reviewed the disposition of these findings and the analytic acceptance justification in accordance with ASME Section XI, IWB-3510.1 and Table 3510-1, and reviewed the results of supplemental UT and PT examinations of the outer and inner surfaces of two additional reactor pressure vessel (RPV) top closure head meridional welds. The inspector also reviewed the visual findings of 12 indications that exceeded the acceptance criteria of ASME Section XI IWB-3520.2(b). The inspector reviewed results of the PT examinations documented in NDE Reports 1-3.00-03-0270 and 1-3.00-03-0271.

The inspector reviewed the results of accepted examinations of VT, PT, MT, RT, or UT of one rod hanger, one seismic restraint, one integrally attached lug, two closure head studs, three containment spray system components (piping), one reactor core spray system component, and three top closure head welds. For each of these components, the inspector reviewed the inspection findings, disposition, selected instrument calibrations, and NDE personnel qualification levels. For each of these inspections performed, the inspector reviewed the disposition of the results in accordance with ASME Section XI.

The inspector reviewed the results of an engineering evaluation of the tie rod lower wedge retainer latch to determine if the 90° and 270° tie rod wedge required replacement during RFO17 to avoid the initiation of inter-granular stress corrosion cracking (IGSCC) during the next operating cycle. The inspector reviewed the design function of the tie rods and reviewed photos of the degraded condition of the tie rod lower wedge retainer latches taken during RFO17. The inspector examined the preliminary disposition, deviation event report (DER) NM-2003-1191, and the corrective action to repair the degraded tie rod lower wedges. The inspector reviewed the licensee evaluation of the apparent cause of the lower wedge degradation, including the assumptions, ASME Code stress evaluation and evaluation for operability through refueling outage eighteen (RFO18).

The inspector reviewed the examination of reactor conical core support weld H9, including UT inspection and characterization of a defect at one location on the circumferential weld and the basis for acceptance for continued operation. The inspector reviewed the request and NRR safety evaluation (SE) to delay completion of the entire weld inspection until RFO18.

The inspector reviewed the results of NDE Report 1-2.07-03-0005 and work order 02-04388-00, which documented the boiling water reactor vessel internals project (BWRVIP) examination findings on the top guide grid beam. The inspector reviewed the preliminary disposition of an indication found on the south side of the top guide grid beam at core location 42-27.

b. <u>Findings</u>

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors reviewed two licensed operator requalification training activity during this inspection period to assess the licensee's training program effectiveness. The inspectors observed Unit 1 licensed operator simulator training on May 29, 2003 and Unit 2 licensed operator training on April 23, 2003. The inspectors reviewed performance in the areas of procedure use, self and peer-checking, completion of critical tasks, and training performance objectives. Following the simulator training, the inspectors observed the crew debrief and critique, and reviewed simulator fidelity through a sampling process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed two performance-based problems during this inspection period involving selected in-scope structures, systems, and components (SSCs) to assess the effectiveness of the maintenance program. Reviews focused on: (1) proper maintenance rule scoping, in accordance with 10 CFR 50.65; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) and (a)(2) classifications; and, (5) the appropriateness of performance criteria for SSCs classified as (a)(2), and goals and corrective actions for SSCs classified as (a)(1). The inspectors reviewed the licensee's system scoping documents, system health reports and corrective action program documents. Additionally, the inspectors performed a walkdown of the systems, and discussed the system status and recent performance with engineering and operations personnel.

The Unit 1 control rod drive (CRD) system was selected for review based on several emergent failures of the CRD pumps during the refueling outage.

The Unit 2 RCIC system was selected for review based on the risk importance of the system and maintenance activities that were conducted.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed eight risk assessments and emergent work activities during this inspection period. For selected maintenance work orders (WOs) or action requests (ACRs), the inspectors evaluated: (1) the effectiveness of the risk assessments performed before the maintenance activities were conducted; (2) risk management control activities; (3) the necessary steps taken to plan and control resultant emergent work tasks; and (4) the overall adequacy of identification and resolution of emergent work and the associated maintenance risk assessments. The following documents were used for this review:

- GAP-MAI-01, Conduct of Maintenance, Revision 3
- GAP-PSH-01, Work Control, Revision 27
- NEG-CA-010, Online Configuration Risk Management Guidance

The following work items/WOs were reviewed:

- Reactor power suppression testing for May 21, 2003 (Unit 2)
- Reactor power suppression testing for May 31, 2003 (Unit 2)
- 345KV phase ‘A’ hot spot repair (Unit 2)
- Control rod display cooling fan failure (Unit 2)
- Repair of a body-to-bonnet leak on the 12 reactor recirculation pump suction isolation valve (Unit 1)
- Planned maintenance on the 103 emergency diesel generator which exceeded its planned duration of five days due to emergent issues (Unit 1)
- Troubleshooting and repair of instability in the flow signal from the 12 reactor recirculation pump which required insertion of a half-scram and operation in that condition for approximately one day (Unit 1).
- A failed level control valve for the 121 heater drain tank which led to an unplanned power reduction to approximately 65 percent (Unit 1)

b. <u>Findings</u>

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed eight operability evaluations during this inspection period, which affected risk significant mitigating systems, to assess: (1) the technical adequacy of the evaluation; (2) whether other existing degraded systems adversely impacted the affected system or compensatory measures; (3) where compensatory measures were used, whether the measures were appropriate and properly controlled; and, (4) that the degraded systems remained operable. The following documents were used for this review:

- NIP-ECA-01, Deviation/Event Reports
- GAP-OPS-02, Administration of Operations, Revision 19
- S-ODP-OPS-0116, Operability Determinations
- 10 CFR 21, Report number 0083 dated August 31, 2002

The following licensee documents were reviewed:

- NM-2003-1792, Drywell vacuum breaker indicating lights (Unit 2)
- NM-2003-2557, Drywell pressure instrumentation (Unit 2)
- NM-2003-1266, Water Found in the Vent Header Junction Regions of the Torus Vent Header (Unit 1)
- NM-2003-1496, Broken Spring on a Reactor Building Closed Loop Cooling System Isolation Valve Actuator in the Drywell (Unit 1)
- NM-2003-1810, Three Hydraulic Snubbers on Emergency Condenser System Piping in the Drywell Found with No Fluid in the Reservoirs (Unit 1)
- NM-2003-2402, 11 Feedwater Pump 2-inch Minimum Flow Valve Opened to 50 Percent Rather Than Full Open During Pump Start (Unit 1)
- NM-2003-2586, Erratic Flow Indication from Reactor Recirculation Pump 12 Required Insertion of a Half Scram on 12 Reactor Protection System (Unit 1)
- NM-2003-1743, Leaking ball joint in RBCLC (Unit 1)

b. Findings

1. High Pressure Coolant Injection System Minimum Flow Valve

Introduction. A Green finding was identified for an inadequate operability determination made on the Unit 1, 11 feedwater pump 2-inch minimum flow valve. Testing of the minimum flow valve was inadequate to establish operability and the valve subsequently failed. The failure of the minimum flow valve rendered the 11 high pressure coolant injection (HPCI) train inoperable. HPCI is an operating mode of the normal reactor feedwater and condensate systems.

Description. On May 17, 2003, the 11 HPCI train was declared inoperable to install a flow controller modification and a 15-day limiting condition for operation (LCO) per TS 3.1.8.b. was entered. During the post-modification testing (PMT), the 11 HPCI 2-inch minimum flow valve (FCV-29-23) was observed to open to 50 percent rather than fully opening as required. This failure was entered into the licensee's corrective action program as DER 1-2003-2402. The operability determination concluded that adequate minimum flow protection was provided for the HPCI pump with the minimum flow valve opened to 50 percent. Following successful completion of the PMT, 11 HPCI train was declared operable later the same day.

On May 18, 2003, the 12 HPCI train was declared inoperable to install the same modification as had been installed on the 11 HPCI train the previous day. During the switch from 12 to 11 feedwater pump as the operating train, FCV-29-23 was observed to open only to approximately 20 percent rather than fully opening. Subsequent review of flow data from the plant computer identified that the valve was passing approximately 10 gallons per minute (gpm) under this condition. Engineering determined that this was insufficient flow to protect the pump under all conditions, and 11 HPCI train was declared inoperable. Since 12 HPCI train was still inoperable due to the modification installation, this required Unit 1 to commence shutdown within one hour per TS 3.1.8.c. However, PMT had already been performed for the 12 HPCI train modification, and the train was declared operable 15 minutes later.

Troubleshooting identified that the pressure regulator for the air supply to FCV-29-23 (an air operated valve) was defective. Following rebuild of the air pressure regulator and controller recalibration, FCV-29-23 was tested satisfactorily and 11 HPCI was declared operable on May 19.

Analysis. The deficiency associated with this event is an inadequate operability determination which led to the conclusion that 11 HPCI train was operable, when in actuality, the 2-inch minimum flow valve failed on the next demand. Operations Administrative Procedure, S-ODP-OPS-0116, Rev. 2, "Operability Determinations," was not correctly implemented, in that the technical basis for operability was not adequately determined for the 11 HPCI train degradation as required. The operability determination was based on the premise that the valve would continue to open to 50 percent during subsequent operation. This had not been substantiated by either troubleshooting or repeated valve performance. Additionally, the valve at 50 percent open was subsequently determined to be inadequate. Also, it was determined that the valve had incorrect trim installed which further degraded performance. The finding is greater than minor because it is associated with the mitigating systems cornerstone attribute of equipment performance and affects the associated cornerstone objective of ensuring the reliability of systems that respond to initiating events. The finding was determined to be of very low safety significance (Green) in accordance with Phase 1 of the Reactor Safety SDP because the finding did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time. The inadequate operability determination was an example of a cross-cutting issue in human performance. The issue was entered NMP's corrective action program as DER 1-2003-2539.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because administrative procedures on operability determinations are not specifically included in the regulatory basis for the technical specification that governs procedure requirements and the allowed outage time for HPCI was not exceeded. FIN 05000220/2003004-01, Inadequate Operability Determination for High Pressure Coolant Injection System.

2. Reactor Recirculation Pump 12 Flow Input to the Average Power Range Monitor Flow Biased Scram

Introduction. A Green finding was identified for an inadequate operability determination regarding intermittent erratic flow indication from Unit 1 reactor recirculation pump (RRP) 12. The original operability determination did not address the effect of the condition on the reactor protection system (RPS). When the condition later persisted, the adverse effect on RPS was recognized, and a half scram was manually inserted.

Description. On June 3, the licensee observed that the flow indication for RRP 12 dropped by approximately 500,000 pounds mass per hour (500 Klbm/hr). The indication persisted, and after investigation it was concluded that the indication from channel 12 flow for RRP 12 could not be considered reliable. Since this channel inputs to RPS through the channel 12 average power range monitor (APRM) flow biased scram, a scram signal was manually inserted to channel 12 RPS. Further troubleshooting traced the problem to the flow instrument square root generator. This was replaced, and channel 12 flow for RRP 12 was declared operable the following day. This issue was entered into NMP’s corrective action program as DER 1-2003-2586.

On May 18, a similar indication of a problem with the 12 RRP flow instrument had been observed. On that occasion, however, indication had returned to its previous level after less than an hour. DER 1-2003-2406 was written for that event, and the associated operability determination was that it was not an operability concern. Review of 12 RRP flow data from the plant computer showed that the problem had occurred on several other occasions between May 18 and June 3, but apparently had not been noted by operators.

Analysis. The deficiency associated with this event is an inadequate operability determination which led to the conclusion on May 18 that 12 RRP flow indication was operable, when in actuality, an intermittent problem had developed which caused the indication to be unreliable. Operations Administrative Procedure S-ODP-OPS-0116, Rev. 2, "Operability Determinations," was not correctly implemented, in that the technical basis for operability was not adequately determined for the 12 RRP flow instrument as required. The operability determination did not take into account that the RRP flow instruments provided input to the RPS. The finding is greater than minor because it is associated with the mitigating systems cornerstone attribute of equipment performance and affects the associated cornerstone objective of ensuring the reliability of systems that respond to initiating events. In addition, if the condition which led to equipment degradation is left uncorrected or not addressed by inserting a manual scram signal, a more significant safety concern affecting RPS could develop. The finding was determined to be of very low safety significance in accordance with Phase 1 of the Reactor Safety SDP because the finding did not represent an actual loss of safety function of a system. The inadequate operability determination was an example of a cross-cutting issue in human performance.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because procedures on operability determinations are not specifically included in the regulatory basis for the technical specification that governs procedure requirements. FIN 05000220/ 2003004-02, Inadequate Operability Determination for Reactor Recirculation Pump Erratic Flow Indication.

1R16 Operator Workarounds

a. Inspection Scope

The inspector reviewed operator workarounds at Units 1 and 2 to determine if any had a potential adverse effect on the functionality of mitigating systems. Included in this review were the effect on (1) the reliability, availability, and potential for mis-operation of a system; (2) the potential increase in initiating event frequency; and (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents. Additionally, the inspector looked for any combined effects of the operator workarounds.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed PMT procedures and associated testing activities for five selected risk significant mitigating systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness, consistent with the design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy for the application; (5) tests were performed, as written, with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The following tests and activities were reviewed:

- N1-IST-LK-101, Reactor Pressure Vessel and ASME Class 1 System Leakage Test, at the completion of major outage activities (Unit 1)

- N1-ST-C2, Solenoid-Actuated Pressure Relief Valves Operability and Flow Verification Test, following repair of pressure relief valve ERV-111 following its failure to actuate during the original performance of the test (Unit 1)
- N1-OP-45, Emergency Diesel Generators, section H.5, EDG 103 Local Starting, performed to support overspeed trip testing of emergency diesel generator (EDG) 103 during its May 5-16 maintenance period (Unit 1)
- Operational testing of the 11 feedwater pump 2-inch minimum flow valve, FCV-29-23 following rebuild of its air supply pressure regulator (Unit 1)
- N2-OSP-EGS-M@001, Monthly Diesel Generator and Diesel Air Start Valve Operability Test - Division I and II, following instrument loop calibrations performed per work orders 03-04325-00, vibration detection, 03-04328-00, DG bearing high temperature trip, and 03-04329-00, DG trip turbocharger thrust bearing failure detector (Unit 2)

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

The inspectors reviewed the following activities related to the Unit 1 refueling outage for conformance to the applicable procedure and witnessed selected activities associated with each evolution. Surveillance tests were reviewed to verify TS were satisfied. Inspections were focused on reactor decay heat removal, spent fuel pool decay heat removal, inventory control, power availability, reactivity control and secondary containment. The inspectors reviewed the outage plan and outage risk mitigation strategies and evaluations. Portions of the shutdown and cool down processes were observed. The following outage activities were observed:

- Shutdown cooling system operation.
- Reactor disassembly.
- Refueling operations.
- Reactor pressure test.
- Plant startups.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed performance of six surveillance test procedures and reviewed test data of selected risk significant SSC's to assess whether the SSC's satisfied Technical Specifications, Updated Final Safety Analysis Report (UFSAR), and licensee procedure requirements; and to determine if the testing appropriately demonstrated that the SSC's were operationally ready and capable of performing their intended safety functions. The following tests were witnessed and/or reviewed:

- N2-OSP-EGS-M@002, Diesel Generator and Diesel Air Start Valve Operability Test -Division III (Unit 2)
- N2-OSP-RMC@001, Control Rod Drive Scram Insertion Time Testing (Unit 2)
- N2-OSP-RHS-Q@004, RHR System Loop A Pump and Valve Operability Test and System Integrity Test and ASME XI Pressure Test (Unit 2)
- N2-OSP-CSH-Q@002, HPCS Pump and Valve Operability and System Integrity Test (Unit 2)
- N1-ST-R2, LOCA and EDG Simulated Auto Initiation Test, Division 1 (Unit 1)
- N1-ST-Q24, Drywell/Torus and Torus/Reactor Building Vacuum Reliefs Test (Unit 1)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Drill Evaluation

a. Inspection Scope

On June 19, 2003, the licensee conducted an EP exercise. The inspectors reviewed the exercise scenario, applicable emergency plan implementing procedures (EPIPs), and emergency action levels (EALs). The inspectors observed licensee performance during the exercise, including event classification offsite authority notification, and dose assessment activities. Mitigation strategies and communications were observed. The inspectors noted the EP equipment and facilities were satisfactorily maintained in the technical support center (TSC), operations support center (OSC), and emergency operations facility (EOF).

The inspectors discussed the post-exercise critique with the site EP manager and also determined that the exercise was appropriate in scope to be included in the EP performance indicator (PI) statistics. The site exercise report and associated DER's which were generated were reviewed. Overall exercise performance was reviewed against criteria contained the Site Emergency Plan.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety and Public Radiation Safety

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspector reviewed calibration methods and documentation of current calibrations of the Shepherd Models 89, 28, and142-10 calibrators; and the high and low well calibrators. These calibrators were used for the calibration of radiation monitoring instrumentation.

The inspector observed the staff performance and reviewed the results of the following station radiation monitor instrument calibrations with respect to industry standards and procedural requirements.

- Unit 2 off-gas pretreatment process radiation monitor 13A monthly calibration verification performed on June 11, 2003
- Unit 1 plant stack radiation monitor quarterly calibration verification performed on June 10, 2003
- Unit 1 guardhouse no. 6 portal monitor annual calibration performed on June 12-13, 2003

The inspector also reviewed the calibration geometries and methods and associated calibration records, for the following permanent in-plant instruments, relative to procedural requirements.

- Unit 1 and 2 refuel platform area radiation monitors (No. 29, RMS-111)
- Unit 1 and 2 control room area radiation monitors (No. 3, RMS-129)
- Unit 1 and 2 transverse in-core probe room area radiation monitors (No. 17, RMS-105)
- Unit 1 and 2 drywell high range gamma monitors (No. 11, RMS-1A)

Portable health physics survey instrument calibration methods and selected in-use instrument calibration documents were also reviewed for the following radiation survey instruments, contamination survey instruments, personnel electronic dosimeters, and air sample counting instruments with respect to industry standards and procedural requirements.

- Eberline 6112B teletectors (4)
- Eberline RO-2/2A ion chambers (6)
- Bicron Frisktech contamination monitors (3)

- Bicron Microrem meters (2)
- Radeco high volume air samplers (3)
- MerlinGerin DMC 2000S electronic dosimeters (5)
- Eberline BC-4 beta counters (3)
- Eberline SAC-4 alpha counters (2)
- Canberra high purity germanium gamma counters (2)

The Nine Mile Point Station Emergency Plan requirements were utilized to verify that the minimum specified self-contained breathing apparatus (SCBA) equipment was properly maintained in the various plant locations. The current control room shift staffing roster was utilized to review selected on-shift control room operators for currency of SCBA use qualifications. Confined space entry and SCBA use procedures and training lesson plans were reviewed with respect to designated rescuer requirements specified in 10CFR20.1703(f).

b. Findings

No findings of significance were identified.

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

a. Inspection Scope

The inspector reviewed the following documents to evaluate the effectiveness of the licensee's radioactive gaseous and liquid effluent control programs for Units 1 and 2. The requirements of the radioactive effluent controls are specified in the Technical Specifications and the Offsite Dose Calculation Manual (TS/ODCM) for Unit 1 and the Improved Technical Specifications and the Offsite Dose Calculation Manual (ITS/ODCM) for Unit 2.

- the 2001 and 2002 Radiological Semi-Annual Effluent Release Reports for Units 1 and 2, including projected public radiation dose assessments;
- current Unit 1 ODCM (Revision 23, October 30, 2002);
- current Unit 2 ODCM (Revision 23, December 20, 2002);
- technical justifications for ODCM and changes made for both units;
- analytical results for charcoal cartridge, particulate filter, and noble gas samples for both units;
- quantifying technique for radioactive materials released through the Unit 1 Emergency Condenser Vent (Procedures N1-SCP-M370 and N1-CSP-V371);
- implementation of the compensatory sampling and analysis program when the effluent radiation monitoring system (RMS) is out of service for both units;
- trending the effluent RMS availability for both units;
- 2002 gamma spectroscopy calibration records of all geometries for both units;
- implementation of measurement laboratory quality control program, including intralaboratory and interlaboratory comparisons for both units;
- status of the Unit 2 GEMS Upgrade Project;
- implementation of IE Bulletin 80-10;

- the 2002 NQA Audit Report (Audit No. 02013) for the implementations of the radioactive liquid and gaseous effluent controls and the ODCM for both units;
- selected radioactive liquid and gaseous release permits for both units;
- associated effluent control procedures for both units;
- most recent surveillance testing results (delta P, in-place testings for HEPA and charcoal filters, air capacity test, and laboratory test for iodine collection efficiency) for the following air treatment systems, as required by 3/4.4.4 and 3/4.4.5 for Unit 1 and Section 5.5.7 (Ventilation Filter Testing Program) of the ITS for Unit 2.

Unit 1 Air Cleaning Systems

- Control Room Air Treatment System; and
- Reactor Building Emergency Ventilation System.

Unit 2 Air Cleaning Systems

- Standby Gas Treatment System;
- Control Room Outdoor Air Special Filter Train System;
- Most recent annual calibration results for: (1) channel calibration and (2) flow rate measurement devices results for Units 1 radioactive liquid and gaseous effluent radiation monitoring system (RMS). These requirements are listed in the Unit 1 ODCM Tables D 4.6.14-1 and D 4.6.14-2.

Unit 1 RMS

- Liquid Radwaste Effluent RMS;
- Service Water Effluent RMS;
- Stack Effluent Noble Gas RMS (Channels A and B for Low and High Ranges);
- Condenser Air Ejector Noble Gas RMS; and
- Emergency Condenser Noble Gas RMS.

Unit 1 Flow Rate Measurement Devices

- Liquid Radwaste Effluent Line Flow Rate;
- Discharge Canal Flow Rate (Circulating Water Pump Performance Test);
- Stack Gas Flow Rate; and
- Condenser Air Ejector Flow Rate.
- Most recent calibration results for: (1) channel calibration and (2) flow rate measurement devices results for Unit 2 radioactive liquid and gaseous effluent radiation monitoring system (RMS). These requirements are listed in the Unit 2 ODCM Tables D 3.3.1-1 and D 3.3.2-1.

Unit 2 RMS

- Liquid Radwaste Effluent RMS;
- Service Water Effluent "A" and "B" RMS;

- Cooling Tower Blowdown RMS;
- Main Stack Noble Gas Monitor RMS (Normal and High Ranges); and
- Reactor/Radwaste Buildings Vent Noble Gas RMS (Normal and High Ranges).

Unit 2 Flow Rate Measurement Devices

- Liquid Radwaste Effluent Flow Rate;
- Service Water Effluent Flow Rates (Channels A and B);
- Cooling Tower Blowdown Flow Rate;
- Reactor/Radwaste Bldg Vent Flow Rate; and
- Main Stack Noble Gas Flow Rate.

The inspector also toured and observed the following systems to evaluate the effectiveness of the licensee's radioactive gaseous and liquid effluent control programs.

- Walkdown for determining the availability of radioactive liquid/gaseous effluent RMS and for determining the equipment material condition;
- Source check process for the Stack Effluent Noble Gas RMS;
- Sampling techniques for charcoal cartridge/filter and preparation for the measurement and for airborne tritium; and
- Walkdown for determining operability of air cleaning systems and for determining the equipment material condition.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP2 Access Control

a. Inspection Scope

The following activities were conducted during the inspection period to verify that the licensee has effective site access controls, and equipment in place designed to detect and prevent the introduction of contraband (firearms, explosives, incendiary devices) into the protected area as measured against 10 CFR 73.55(d) and the Physical Security Plan and Procedures:

Site access control activities were observed, including personnel and package processing through the search equipment during peak ingress periods on May 6 and 7, 2003. On May 7, 2003, observation of vehicle search activities was also conducted. On May 6, 2003, testing of all access control equipment; including metal detectors, explosive material detectors, and X-ray examination equipment, at both access points, was observed.

b. Findings

No findings of significance were identified.

3PP3 Response to Contingency Events

a. Inspection Scope

The following activities were conducted to determine the effectiveness of Nine Mile Point's response to contingency events, as measured against the requirements of 10 CFR 73.55 and the Nine Mile Point Safeguards Contingency Plan:

On May 7, 2003, a review of documentation associated with the licensee's force-on-force exercise program was conducted. The review included documentation and critiques for exercises conducted since the first quarter of 2002, when the exercises were resumed post 9/11/01.

On May 7, 2003, performance testing of the Nine Mile Point intrusion detection and alarm assessment systems was conducted. This testing was accomplished by one inspector who toured the entire perimeter and selected, and subsequently performance tested, areas of potential vulnerability in the intrusion detection system. Concurrently, a second inspector observed the alarm assessment capabilities from the Central Alarm Station. During the walkdown of the intrusion detection system, twenty specific locations were selected for testing.

b. Findings

No findings of significance were identified.

3PP4 Security Plan Changes

a. Inspection Scope

An in-office review was conducted of changes to the licensee's Training and Qualification Plan identified as Issue 4, Revision 1 and the licensee's Physical Security and Safeguards Contingency Plan identified as Issue 5, Revision 4. These documents were submitted to the NRC on January 7, 2003, in accordance with the provisions of 10 CFR 50.54(p). The review was conducted to confirm that the changes were made in accordance with 10 CFR 50.54(p), and did not decrease the effectiveness of the above listed plans. The NRC recognizes that some requirements contained in these Plans may have been superceded by the February 2002 Interim Compensatory Measures Order.

b. Findings

No findings of significance were identified.

4 OTHER ACTIVITIES

4OA1 Performance Indicator Verification

a. Inspection Scope

On May 8, 2003, a review was conducted of the licensee's programs for gathering, processing, evaluating, and submitting data for the Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment PIs to verify these PIs had been properly reported as specified in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 1 and Rev. 2. The review included the licensee's tracking and trending reports, personnel interviews and security event reports for the PI data collected from the 2nd quarter of 2002 through March 2003.

b. Findings

No findings of significance were identified.

40A2 Identification and Resolution of Problems

1. Inservice Inspection Activities

a. Inspection Scope

The inspector reviewed samples of dispositions of ISI findings that were accepted or rejected in the ISI related reports in Attachment 1. For each case, the inspector verified that problems identified by ISI were evaluated, reviewed by staff, and where appropriate, were placed into the corrective action program for repair or replacement.

b. Findings

No findings of significance were identified.

2. Radiation Monitoring Instrumentation

a. Inspection Scope

The inspector reviewed four DERs (2003-562, 2003-747, 2003-753 and 2003-767) that were initiated from October 2002 through May 2003 and were associated with the occupational radiation safety cornerstone. The purpose of the review was to evaluate the licensee's effectiveness at properly identifying, characterizing, investigating and resolving problems in implementing the licensee's radiation protection program.

b. Findings

No findings of significance were identified.

3. Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

a Inspection Scope

The inspector reviewed the following Deviation Event Reports (DERs) to evaluate the effectiveness of the licensee's problem identification and resolution processes in the areas of radioactive liquid and gaseous effluent control programs:

- DERs for Routine Effluent Control Program; (2000-0683, 2002-367, 2002-2040, 2002-2042, 2002-3999, 2002-4001, 2002-4726, 2002-2037 and 2003-810)
- DERs for Air Cleaning Systems; (2001-86 and 2001-1448) and
- DERs for Radiation Monitoring Systems; (2003-1054, 2003-1645, 2002-241, 2002-0913, 2002-4315, 2002-4625, 2002-4720, 2002-5421, 2001-5020, 2001-5607 and 2001-5215).

b. Findings

No findings of significance were identified.

4. Adequacy of Nine Mile Point Unit 1 (NMP1) 115 kV Offsite Sources

a. Inspection Scope

The inspectors reviewed DER NM-2002-4708 to ensure that the corrective actions for the associated plant issues were appropriate. The DER was issued when the licensee determined that the contingency voltage of one of the Unit 1 offsite sources, 115 kV line No. 4, was low and that the line would not be able to support loss of coolant accident (LOCA) loads. The low voltage condition on Line 4 was recorded while the other source, Line 1, was out of service. This issue, also addressed in Licencee Event Report (LER) No. 50-220/2002-001, was selected for follow-up review because of its potential safety significance in the initiating event and mitigation systems cornerstones.

The inspectors reviewed the circumstances surrounding the event, the identification process, and the event evaluation performed by the licensee, including the apparent and root cause evaluation. The inspectors verified that the corrective actions were commensurate with the significance of the issue, reasonable, adequately supported by the licensee's analyses, and correctly implemented. The inspectors also reviewed the licensee's actions regarding extent of condition, generic implications, timeliness of corrective action, actions to prevent recurrence, and identification of the root and contributing causes of the problem. Applicable records, including maintenance and test activities were reviewed as necessary. Lastly, the inspectors reviewed the licensee's interfaces with external organizations and discussed with responsible licensee personnel the human performance issues pertaining to the event.

b. Findings

Introduction. A Green self-revealing finding was identified concerning corrective actions associated with the 115kV offsite power sources. The licensee failed to preclude recurrence of a significant condition adverse to quality that had been previously recognized and included in the plant corrective action program.

Description. NMP1 has two 115kV offsite power sources, Line 1 from the South Oswego Station and Line 4, through Line 3, from the Lighthouse Hill Station. On September 7, 2001, Niagara Mohawk Power Corporation (NMPC) determined that Line 4 could not provide the non safety-related offsite power for design basis accident loads, while Line 1 was out-of-service (LER 05000220/2001-002). As a result of this event, the licensee initiated action to raise the nominal bus voltage by changing the transformers tap setting. In addition, National Grid Power Control (NGPC) put into service a "Power Control State Estimator Program," to calculate the grid voltage for various contingencies under real time grid load flow conditions. This program can alert NGPC when the contingency voltage on the grid is inadequate to support NMP1 operation and allow them to take actions to raise voltage above the alarm set-point. The NRC reviewed the actions resulting from this event and found them acceptable (IR 05000220; 410/2002-005).

On November 1, 2002, NGPC notified NMP1 that Line 1 would be removed from service for approximately ten hours to allow maintenance activities. Prior to the removal of Line 1 from service, NGPC ran the estimator program and determined that the grid voltage would drop below the contingency voltage (i.e. below the minimum voltage required to prevent separation of the emergency buses from the grid in the event of a design basis accident). This fact was not effectively communicated to the NMP1 operating staff prior to removing Line 1. Following the removal of Line 1 from service, the program was run again and the low contingency grid voltage condition was communicated to the NMP1 staff. The plant implemented Technical Specification required actions as documented in DER NM-2002-4708 and LER No. 50-220/2002-001.

The licensee's evaluation of the event determined that it was caused by inadequate validation and verification of the administrative process governing the interfaces between NMP1 and NGPC. The evaluation also concluded that inadequate training and understanding of the governing procedures by the responsible NMP1 and NGPC staff contributed to the lack of communication between the two organizations. As a result of this event, the licensee initiated actions to revised the policies and operating procedures. These revisions were focused on assuring that effective communications would exist between the two organizations. The licensee also initiated additional training for NMP1 and NGPC operating staff as well as engineering and support staff. The licensee is also evaluating design modification alternatives to improve the offsite source voltage control and to minimize reliance on administrative controls for maintaining grid voltage.

The inspectors review of DER NM-2002-4708, LER No. 50-220/2002-001, and the root cause evaluation concluded that the resulting corrective actions were appropriate. The inspectors also concluded that, although the corrective actions resulting from the September 7, 2001 event were adequate to address the issue of grid voltage, they were not properly implemented and, hence, failed to prevent recurrence of the event.

Analysis. The inspectors determined that the failure to adequately implement the corrective actions associated with Unit 1 offsite power sources was more than minor because it resulted in the degradation of the offsite power source and is an example of a cross-cutting issue in problem identification and resolution. The failure to assure operability of Line 4, while Line 1 was out of service, degraded the reliability of the offsite electrical system. This issue is applicable to the mitigating system cornerstone because the offsite electrical system provides a source of power to emergency equipment. The finding was determined to be of very low safety significance (Green) in accordance with Phase I of the Reactor Safety SDP, because the accident mitigating systems remained operable, there was no loss of electrical system safety function, and no technical specification limiting conditions for operation were exceeded.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a non-compliance because the 115kV system is non-safety related. FIN 05000220/2003004-03, Inadequate Corrective Actions Associated With Loss of 115 kV.

4OA3 Event Follow-up

1. (Closed) LER 50-220/2002-002, Loss of One Control Rod Drive Pump Train Due to Circuit Breaker Failure

a. Inspection Scope

The inspectors reviewed the LER and DER 2002-4518 to verify that the cause of the October 17, 2002, Unit 1 event was identified and that the corrective actions were reasonable. The failure of the control rod drive pump circuit breaker was due to a defective over current trip device. The inspectors reviewed licensee staff implementation of Technical Specifications and verified operability of the remaining control rod drive pump.

b. Findings

Introduction. A Green self-revealing NCV was identified for failure to implement a procedure in accordance with Technical Specification 6.8.1, which resulted in a control rod drive pump being inoperable for 25 days.

Description. On October 17, 2002, a self-revealing finding was identified when the 12 control rod drive pump failed to start during routine surveillance testing. The pump was observed to begin rotation then coast to a stop. Troubleshooting confirmed that the breaker had attempted to shut and immediately tripped open. A spare circuit breaker was installed and the CRD pump successfully started. Maintenance on the original breaker had been conducted on September 24, 2002. As part of that maintenance, a failed over current trip device was replaced. The post maintenance testing conducted to verify operability of the pump was performed with the breaker racked out to the " test" position, rather than in the "racked in" position. Testing of the breaker in this manner verifies the breakers control circuitry, but does not pass load current through the over current trip device. The licensee determined that the root cause of the event was inadequate post maintenance testing instructions that failed to identify a defective circuit breaker over current trip device.

Analysis. The inspectors determined that the finding is a procedure non-compliance, in that the work order for post maintenance testing of the 12 CRD pump breaker did not require performance of the 12 CRD pump surveillance as required by Nine Mile Point General Administrative Procedure, GAP-SAT-02, Pre/Post-Maintenance Test Requirements, Attachment 2. The Work Order did not specify performance of the surveillance test, but only required the cycling of the breaker which was racked to the test position. The finding was greater than minor because it had an actual impact of causing the CRD pump to be inoperable for greater than Technical Specification allowed outage time. The finding, which is under the mitigating systems cornerstone, was of very low safety significance because the exposure time for this condition was less than 30 days and all other mitigation capabilities described on the SDP Phase 2 worksheet were maintained.

Enforcement. TS 6.8.1 states, in part, that, "Written procedures . . . shall be established, implemented and maintained . . ." Contrary to the above, General Administrative Procedure GAP-SAT-02, "Pre/Post-Maintenance Test Requirements" was not implemented correctly on September 24, 2002, in that the surveillance test for the 12 CRD pump was not performed to verify Technical Specification operability after breaker maintenance. As a result the 12 CRD pump was inoperable for greater than its allowed outage time of 7 days per TS 3.1.6. Because this procedural non-compliance is of very low safety significance and has been entered into the corrective action program, (DER 2002-4631), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000220/2003004-04, Inadequate Post

Maintenance Test Resulted in Control Rod Drive Pump Being Inoperable for Greater than TS Allowed Outage Time.

2. (Closed) LER 50-220/2002-001, 115 Kilovolt Offsite Power Inoperable Due to Low Voltage on Line 4 and Line 1 Out of Service.

   The LER was written to document the low contingency voltage alarm on offsite source Line 4 while the other source, Line 1, was out of service. The inspectors determined that the licensee entered the issue into the corrective action program. Issues associated with this event are addressed in section 4OA2.4 of this report. This LER is closed.

3. (Closed) LER 50-410/2001-005, Maximum Licensed Power Exceeded Due to Non-Conservative Moisture Carryover Fraction

   In October 2001, NMPNS became aware that General Electric (GE) had identified a potentially non-conservative input to the thermal power calculations used for BWR-4 and later model plants. Specifically, the value of the moisture carryover fraction had been shown by actual measurements to be significantly less than the GE-specified value of 0.1 percent. As a result, it was possible that NMPNS unit 2 (NMP2) had been operating above their licensed maximum power level of 3467 megawatts-thermal (MWt) by as much as 2 MWt. This issue was entered into the corrective action program as DER 2001-4578. In response to this issue, NMP2 reduced power by 2 MWt and administratively limited power to 3465 MWt pending further evaluation. Moisture carryover testing established that the actual value of the moisture carryover fraction was approximately 0.0 percent. Review of historical data, coupled with the actual value of the moisture carryover fraction, identified that there had been instances when NMP2 had exceeded its thermal limit by approximately 2 MWt.

   NMPNS determined that the apparent cause of this event was inadequate design inputs by GE. Long term corrective action was to change the value of the moisture carryover fraction used by the plant process computer for thermal power calculation from 0.1 percent to 0.0 percent.

   The inspectors reviewed this LER and no findings of significance were identified. Although the event constituted a violation of a license condition, it was not the result of a licensee performance deficiency and therefore was not evaluated as a potential finding. This LER is closed.

4. (Closed) LER 50-410/2002-002, Reactor Water Cleanup System Differential Flow Isolation Signal Inoperable

   On March 16, 2002, NMP2 during a normal reactor shutdown for refueling outage 8, abnormal indications were observed from the reactor water cleanup (RWCU) system differential flow instruments. The instruments were declared inoperable and the applicable TS action statement was entered and completed. NMPNS determined that the cause of the RWCU differential flow instrument malfunctions was inadequate filling and venting of the system following maintenance. Corrective actions included modification of the RWCU operating procedure to include venting the differential flow transmitter instrumentation during system restoration. No new findings were identified in the inspector's review. This issue is of minor significance because the system remained capable of performing its safety function of isolating the RWCU system in the event of a system rupture. This issue was entered into the corrective action program as DER 2002-1054. This LER is closed.

5. <u>(Closed) LER 50-410/2002-005</u>, Oscillation Power Range Monitors Inoperable Due to Non-conservative Minimum Oscillation Period Setting

   On November 22, 2002, NMPNS received a Part 21 notification from GE that a setup parameter used for the oscillation power range monitors (OPRM) at NMP2 may be non-conservative. Based on improved modeling techniques, GE determined that NMP2 could be susceptible to thermal hydraulic instabilities of a shorter period than had previously been analyzed. As a result, the minimum oscillation period used for the OPRM's detection algorithm needed to be reduced from 1.4 seconds to 1.2 seconds. This issue was entered into the corrective action program as DER 2002-4992.

   NMPNS determined that the apparent cause of this event was inadequate design considerations by GE. Corrective action was to change the minimum oscillation period setting to 1.2 seconds.

   The inspectors reviewed this LER and no findings of significance were identified. Although the event constituted a violation of a license condition, it was not the result of a licensee performance deficiency and therefore was not evaluated as a potential finding. This LER is closed.

6. <u>(Closed) LER 50-220/2002-003</u>, Loss of Power to Reactor Protection System (RPS) Bus 12 While RPS Bus 11 Emergency Power Source Was Inoperable

   On December 2, 2002, Unit 1 bus 12 RPS power was lost while the opposite train RPS bus 11 emergency power source was inoperable due to maintenance. RPS bus 11 remained energized. The licensee restored the emergency power source (diesel generator) for bus 11 to service prior to exceeding the Technical Specification action statement. NMPNS replaced the failed power supply and reestablished the normal power source for the 12 RPS bus. The inspectors reviewed this LER and no findings of significance were identified. The licensee documented the failed equipment in DER 2002-5093. This LER is closed.

7. <u>(Closed) LER 50-410/2002-001</u>, Automatic Scram Signal During Refueling Outage Due to Inadequate Instrument Air Isolation Procedure

   On March 21, 2002, with Unit 2 shutdown for refueling, a full scram signal was generated on high water level in the scram discharge volume (SDV). The high level in the SDV occurred when air pressure in the scram air header bled down after service air was isolated, which caused the scram valves to fail open. Water entered the SDV via the scram valves from the hydraulic control units, as designed. Air pressure from the service air system was inadvertently lost due an inadequate procedure which isolated the instrument air system without ensuring an alternate air supply to the service air system. The procedure for isolating instrument air was new and had not been adequately reviewed. The inspectors reviewed this LER and no findings of significance were identified. The licensee documented the inadequate procedure in DER 2002-1241. This LER is closed.

8. <u>(Closed) LER 50-410/2002-006,</u> Reactor Scram Due to Loss of Generator Stator Cooling

On December 16, 2002, Unit 2 automatically scrammed from 71 percent power due to high reactor pressure. The event was initiated by a main electrical generator stator water cooling system load set runback due to the failure of the stator cooling water temperature control valve. The control valve failure to the minimum cooling position was caused by a failure of the feedback mechanism. The controller was installed in a manner which exposed it to high vibration which, over time, caused the feedback mechanism to fail. The licensee noted that recognition of past industry operating experience (OE) in the form of LERs could have prevented occurrence of the event. At the time, industry LERs were not routinely screened as part of the licensee's OE program. The initial followup of the event was documented in Section 40A3.2 of the NRC Inspection Report 50-410/2002-06. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the event in DERs NM-2002-5312 and 5314. This LER is closed.

9. <u>(Closed) LER 50-410/2002-004</u>, Reactor Trip Due to Main Steam Isolation Valve Failure

On November 11, 2002, Unit 2 automatically scrammed from 100 percent power due to high reactor vessel pressure, caused by the unexpected, sudden closure of a main steam isolation valve (MSIV). Initially, one MSIV closed due to disc/stem separation; the ensuing pressure pulse caused a high steam flow condition, which was sensed in the other three main steam lines resulting in automatic closure of the other seven inboard and outboard MSIVs as designed. The cause of the MSIV failure was a deficient design from the manufacturer that did not ensure the proper stem-to-disc thread loading. The deficient design resulted in the mechanical separation at the stem-to-disc threaded and pinned connection due to vibration. A modification to upgrade the MSIVs had been performed on five of the eight MSIVs. The primary purpose of the modification was to improve the leak tightness of the MSIVs while also incorporating a one-piece piston/disc assembly and a welded stem-to-disc design. The subject MSIV had not been modified. During the shutdown, the three remaining MSIVs were modified with the improved design. The initial followup of the event was documented in Section 40A3.1 of NRC Inspection Report 50-410/2002-06. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the event in DER NM-2002-4811. This LER is closed.

10. <u>(Closed) LER 50-410/2002-003</u>, Open Door Between the Control Building and the Auxiliary Building Results in Breach of the Control Room Envelope

On September 29, 2002, an operator found a control room envelope door open which resulted in an inoperable control room envelope boundary. The plant entered the Technical Specification action statement for the control room envelope filtration (CREF) system and the door was immediately closed. An investigation conducted by Security determined that the door had been open for 59 minutes. The door was designed to close automatically, but had become jammed on the floor and the last person through the door had failed to ensure that it was shut. The door is required to be closed to ensure that the CREF system can perform its function. Since the door was open for a short time, and security force members, the fire chief and operators make periodic rounds, the inspectors concluded that the issue was minor. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented the event in DER NM-2002-4233. This LER is closed.

4OA6 Meetings, Including Exit

On July 11, 2003, the resident inspectors presented the inspection results to Mr. L. Hopkins, Plant General Manager, Nine Mile Point, and other members of licensee management who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

R. Dean, General Supervisor, Design Engineering
G. Detter, Manager, Support Services
J. Gerber, ALARA Supervisor
L. Hopkins, Plant General Manager
J. Jones, Supervisor, Emergency Preparedness
S. Minahan, Manager, Site Operations
B. Montgomery, Manager, Engineering Services
W. Paulhardt, Radiation Protection Manager
B. Randall, General Supervisor, System Engineering
C. Terry, Manager, Quality and Performance Assessment
D. Wolniak, General Supervisor, Licensing

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

NONE

Opened and Closed

05000220/2003004-01	FIN	Inadequate Operability Determination for High Pressure Coolant Injection System (Section 1R15)
05000220/2003004-02	FIN	Inadequate Operability Determination for Reactor Recirculation Pump Erratic System Flow (Section 1R15)
05000220/2003004-03	FIN	Inadequate Corrective Action Associated With Loss of 115 kV (Section 4OA2)
05000220/2003004-04	NCV	Inadequate Post Maintenance Testing for the Control Rod Drive Pump Resulted in it Being Inoperable for Greater than the TS Allowed Outage Time (Section 4OA3)

Closed

50-220/2002-001	LER	115 Kilovolt Offsite Power Inoperable Due to Low Voltage on Line 4 and Line 1 Out of Service (Section 4OA3)
50-410/2001-005	LER	Maximum Licensed Power Exceeded Due to Non-Conservative Moisture Carryover Fraction (Section 4OA3)

50-410/2002-002	LER	Reactor Water Cleanup System Differential Flow Isolation Signal Inoperable (Section 4OA3)
50-410/2002-005	LER	Oscillation Power Range Monitors Inoperable Due to Non-conservative Minimum Oscillation Period Setting (Section 4OA3)
50-220/2002-003	LER	Loss of Power to Reactor Protection System (RPS) Bus 12 While RPS Bus 11 Emergency Power Source Was Inoperable (Section 4OA3)
50-410/2002-001	LER	Automatic Scram Signal During Refueling Outage Due to Inadequate Instrument Air Isolation Procedure (Section 4OA3)
50-220/2002-002	LER	Loss of One Control Rod Drive Pump Train Due to Circuit Breaker Failure (Section 4OA3)
50-410/2002-006	LER	Reactor Scram Due to Loss of Generator Stator Cooling (Section 4OA3)
50-410/2002-004	LER	Reactor Trip Due to Main Steam Isolation Valve Failure (Section 4OA3)
50-410/2002-003	LER	Open Door Between the Control Building and the Auxiliary Building Results in Breach of the Control Room Envelope (Section 4OA3)

Discussed

NONE

LIST OF DOCUMENTS REVIEWED

Licensing Documents

Nine Mile Point Unit 1 - Final Safety Evaluation Report (Updated)
Nine Mile Point Unit 2 - Updated Safety Analysis Report

List of Documents Reviewed

Security Plan and Procedure Audit Number 2003-018, March 4, 2003
Safeguards Event Log, March 2002 - March 2003.
Nine Mile Point Nuclear Station Physical Security and Contingency Response

Inservice Inspection Schedules and Programs

NMP1-RI ISI-003	ISI Program - Third ISI Interval - Alternate Risk Informed ISI Plan and Schedule Rev 00 10/11/2002
NMP1RFO17-SCHED	Third ISI Interval - Refueling Outage Seventeen (RFO17) Rev 04 - Final Scope Reduction Schedule 03/05/2003

EPRI Documents

EPRI Proprietary	BWRVIP Safety Assessment of BWR Internals Section 2.0 - Shroud Support Designs and Susceptibility Information

NRC (TAC No.M99638) Final Safety Evaluation of the BWR Vessel and Internals Project, BWR Shroud Support Inspection and Flaw Evaluation Guidelines (BWRVIP-38)," EPRI Report TR-108823

BWRVIP (EPRI) Documents

BWRVIP-14	Evaluation of Crack Growth in BWR Stainless Steel RPV Internals
BWRVIP-18	BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines
BWRVIP-48	Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines

In-Vessel Core Shroud Stabilizer Tie Rod Assembly Inspection and Repair

NER-1M-053	NMP1Core Shroud Stabilizer Assemblies In-Vessel Re-Inspection and Evaluation, Rev 2, 10/10/01
DER NM-2003-1191	Preliminary Disposition of Lower Wedges and Core Shroud Tie Rods Having Moved Downward in Excess of Procedure Acceptance 04/01/03
NM-2003-1191	Measured Tie Rod Lower Wedge Displacement Exceeds Acceptance of Procedure NDEP-VT-2.06 Rev 1.

Core Shroud Support Weld H9 Inspection Results

EPRI TR-108823	BWR Vessel and Internals Project, BWR Shroud and Support Inspection and Flaw Guidelines (BWRVIP-38) 09/1997
H9 UT Indications	H9 Vessel OD Coverage Estimates
G Inch	NMP1 Shroud Support Inspection and Evaluation Summary Report (Slides)
NMPIL 1603	Inspection Results for Core Support Welds H8 and H9 08/02/2001
KR Wichman	NMP1: Safety Evaluation of the Flaws in Core Shroud Support Welds H8 and H9 (TAC NO. MB2528) 10/17/2001
Docket 50-220	Safety Evaluation by the Office of NRR - NMP Unit 1 - Schedule Extension of BWRVIP Project (BWRVIP-38 Supplemental Inspection of Core Shroud Support Weld Attachment H9 Supplementing Inspection of Core Shroud Weld Attachment H9 at NMP Unit 11
PS Tam, USNRC	Letter to JT Conway NMP1 - Inspection of Core Shroud Support Weld H9 (TAC NOMP6893) 03/20/2003, Docket 50-220

NMP1-03-025	Wghs Exam Summary Sheet - H9 Weld Core Shroud to Vessel Weld 3/26/2003, Including UT Exam Data Sheets, Data Acquisition Log, NMP1H9SCAN1A, Calibration Data Sheets, 24 pages
NMP1L 1702	Inspection of Core Shroud Weld 12/13/2002

Reactor Pressure Vessel Top Head Inspection Results

1-6.27-03-001	RPV-WD-005 UT Results of Meridional Weld Examinations (3 Sheets) 03/26/2003
NMP1-03-00	RPV Head (Top) UT Results of Meridional Weld Examinations (12 Sheets) 03/22/2003
1-3.00-03-0284	RPV Head Internal Surface PT Weld Examination Results 03/24/2003
1-3.00-03-0270/0271	PT Examinations of Meridional Weld Indications
DER-NM-2003-1344	Screened Identification ISI UT Exam of Meridional Weld RV-WD-005 Indication Detection Exceeding ASME XI IWB-3510.

Top Guide Grid Beam Examination

1-2.07-03-0005	In-vessel Visual Inspection Report
WO 02-04-04388-00	IVVI Report Attachment 5

Miscellaneous Non-Destructive Examination Reports

1-2.01-03-0023	ASME XI VT-3 Report of 93-R13-B Rod Hanger 02/05/2003
1-2.01-03-0029	ASME XI VT-3 Report of 93-SCR-9G Seismic Restraint Exam 02/07/2003
1-4.00-03-0013	MT Report of 80-H59-WD-001 Integrally Attached Lug Exam 03/06/03
1-4.00-03-0019	MT Report of 81-H38-WD-001 Reactor Core Spray Exam03/10/2003
1-6.25-03-0002	UT Report of CH-23-B thru CH-43-B Clos Head Stud Exam 03/17/2003
1-6.25-03-0003	UT Report of CH-23-B thru CH-43-B Clos Head Stud Exam 03/24/2003
1-6.23-03-0002	UT Report of 80-WD-194 Containment Spray System Exam 03/06/2003
1-6.23-03-0012	UT Report of 81-WD-111 Reactor Core Spray System Exam 03/15.2003
1-6.23-03-0001	UT Report of 80-WD-194 Containment Spray System Exam 03/06/2003
1-6.23-03-0010	UT Report of 81-WD-111 Containment Spray System Exam 03/11/2003
1-6.23-03-0011	PT Report RV-03-1-CH Closure Head 03/19/2003 03/26/2003 6 pages
1-3.00-03-0271	PT Report RV-03-1-CHC Closure Head 3/21/2003
1-2.01-03-0076	VT-3 Report RV-03-1-CHC Closure Head 03/19/2003

Deviation/Event Reports

NM-1995-3242, NM-1998-814, NM1998-2229, NM-2000-1465, NM-2001-3251, NM-2002-4708, NM-2002-5136

Policies and Procedures

N1-OP-33A	115 KV System, Revision 21
NEP-DES-29	Transmission System Design Interface, Revision 1
PCO 2-1	Power Control Order - Normal Operation and Definition of Emergency Conditions, dated May 1, 1999
S-ODP-OPS-0112	Off-Site Power Operations and Interface, Revision 3

Policy 4.42 NMPNS, LLC-NMPC	Nine Mile Point 1 & 2 and FitzPatrick Post Contingency Voltage Alarm Operating Guidelines

Licensee Event Reports

05000220/2001-002	115 Kilovolt Line 4 Inoperable Due to Inadequate Analysis of Design Change, Revision 00
05000220/2002-001	115 Kilovolt Offsite Power Inoperable Due to Low Voltage on Line 4 and Line 1 Out of Service, Revision 00

Miscellaneous Documents

Memorandum of Understanding between Power Control, Regional Control, Energy Services, Electric and Gas Operations and Nine Mile Point Units 1 and 2, dated October 25, 2000
UFSAR Section IX - Electrical System, Revision 17
TS Section 3.6.3 - Emergency Power Sources
C.V. Mangan (NMPC) Letter to D. B. Vassallo (NRC) dated December 22, 1983
Constellation/National Grid Operating Committee Meeting Minutes, dated December 5, 2002
Consent to Assignment by Erie Boulevard Hydropower, L.P.- Nine Mile Point One Emergency Power Supply Agreement, dated June 30, 1999
Attachment 1 Lesson Plan O3-OPS-003-314-3-01, Revision 0, Power Grid System Control
System Design Basis Document - SDBD 803, AC Electrical Distribution System, Revision 4

Calculations/Studies

4.16KVAC-PB102/103SETPT/27, Degraded Voltage Relay Setpoint, Revision 2
ELMSAC-DEGVOLT-STDY, Degraded Voltage Analysis, Revision 0
NER-1E-015, NMP1 Offsite Grid Voltage Regulation Study, Revision 0
SAS-02-022, Line 1 OOS and Degraded Voltage on Line 4, Revision 0
SAS-02-023, Line 1 OOS and Degraded Voltage on Line 4, Revision 1

Specifications

E-174, Grid Interface Specification Nine Mile Point Units 1 and 2, Revision 1

Drawings

GE 104R853	BWR Reactor Vessel & Instruments - Full Cross Section
GE E-231-574	Reactor Top Closure Head
GE E 231-560-1	General Arrangement- Elevation

Inspection Procedures Used

71121 - Radiation Monitoring Instrumentation
71122 - Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems
71130 - Physical Protection
71151 - Performance Indicator Verification

LIST OF ACRONYMS

AC	alternating current
ALARA	as low as is reasonably achievable
CFR	Code of Federal Regulations
CR	condition report
CRD	control rod drive
DERs	deviation event reports
DRS	Division of Reactor Safety
EAL	emergency action level
EDG	emergency diesel generator
EPIP	emergency plan implementing procedures
HEPA	high-efficiency particulate air (filter)
ICMs	interim compensatory measures
IR	inspection report
ISI	inservice inspection
IVV	internals vessel visual inspection
kV	kilovolt
LER	licensee event report
LOCA	loss of coolant accident
MT	magnetic particle testing
NCV	non-cited violation
NDE	non-destructive examination
NGPC	national grid power control
NMPC	niagara mohawk power corporation
NMP1	nine mile point unit 1
NRC	U.S. Nuclear Regulatory Commission
PMT	post-maintenance testing
PT	penetrant test
QA	quality assurance
QC	quality control
RFO17	refueling outage 17
RPV	reactor pressure vessel
RSPS	risk significant planning standard
RT	radiographic test
SCBA	self-contained breathing apparatus
SDP	significance determination process
SE	safety evaluation
SIL	safety information letter
SSCs	structures, systems, and components

SSS	station shift supervisor
TS	technical specifications
UFSAR	updated final safety analysis report
WOs	work orders