September 14, 1999

Mr. John H. Mueller
Chief Nuclear Officer
Niagara Mohawk Power Corporation
Nine Mile Point Nuclear Station
Operations Building, 2nd Floor
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NRC SPECIAL INSPECTION REPORT NOS. 50-220/99-06 AND 50-410/99-06

Dear Mr. Mueller:

This report transmits the findings of a special inspection conducted by NRC inspectors at the Nine Mile Point Nuclear Station, Units 1 and 2, from June 20 through July 31, 1999. The report details focus on the activities associated with and following the automatic and planned reactor shutdowns of Unit 2 on June 24 and July 2, respectively. A special inspection was conducted to ensure that the plant equipment and staff performance problems associated with these shutdowns were appropriately addressed prior to the restart of the unit. At the conclusion of the inspection, the findings were discussed with members of your staff.

During this special inspection period, the overall conduct of operations at the Nine Mile Point Nuclear Station reflected an acceptable safety focus. However, a number of longstanding equipment reliability and material condition issues adversely impacted recent Unit 2 operations and challenged the plant operators. Of most concern were the staff and equipment performance issues related to the reactor coolant isolation cooling (RCIC) system problems experienced following the June 24 automatic reactor shutdown. These issues, and the previous failure of the RCIC system to function following the April 24, 1999, automatic shutdown, reflected poor RCIC system reliability and revealed weaknesses in the maintenance and engineering support of the system and the corrective action process.

We note that you and your staff acknowledged these recent performance shortcomings at the exit meeting and that NMPC had demonstrated a commitment to reverse this trend by making the decision to shutdown Unit 2 on July 2. The unit was not restarted until the RCIC and residual heat removal systems' testable check valve problems were thoroughly investigated and resolved. I encourage you and your staff to continue your efforts to address these performance shortcomings and issues involving management leadership and oversight, and communications.

Based on the results of this inspection, the NRC has determined that two Severity Level IV violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCV), consistent with Appendix C of the Enforcement Policy. The NCVs are described in the subject inspection report and involved the failure to have appropriate procedures to ensure proper performance and documentation of all required RCIC system tuning and calibration and the failure to perform inservice testing of 26 safety valves. If you contest the violation or severity level of these NCVs, 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, DC 20555-0001, with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the Nine Mile Point Facility.

In accordance with 10CFR2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be placed in the NRC Public Document Room.

Sincerely,

Original Signed By:

Richard V. Crlenjak, Deputy Director
Division of Reactor Projects

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

Enclosures:
1) NRC Inspection Report Nos. 50-220/99-06 and 50-410/99-06
2) June 25, 1999, Management Meeting NMPC Handout
3) List of Attendees

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J. Rettberg, New York State Electric and Gas Corporation
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report Nos.:	50-220/99-06 50-410/99-06
License Nos.:	DPR-63 NPF-69
Licensee:	Niagara Mohawk Power Corporation P. O. Box 63 Lycoming, NY 13093
Facility:	Nine Mile Point, Units 1 and 2
Location:	Scriba, New York
Dates:	June 20, 1999 - July 31, 1999
Inspectors:	G. K. Hunegs, Senior Resident Inspector W. L. Schmidt, Senior Resident Inspector, Three Mile Island J. M. Trapp, Senior Reactor Analyst R. L. Fuhrmeister, Engineer, Division of Reactor Safety (DRS) S. K. Chaudhary, Engineer, DRS R. A. Fernandes, Resident Inspector
Approved by:	Michele G. Evans, Chief Projects Branch 1 Division of Reactor Projects

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/99-06 & 50-410/99-06
June 20, 1999 - July 31, 1999

This special inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covered a six-week period of inspection by the residents and region based inspectors. The inspections focused on activities associated with and following the Unit 2 automatic reactor shutdown which occurred on June 24.

Operations

On June 24, an automatic reactor shutdown from 100 percent power occurred at Unit 2 during maintenance on the feedwater control system. Operators placed the plant in a stable condition; overall, operator performance was adequate. Several equipment performance problems, combined with an off-normal plant electrical lineup, resulted in increased challenges to plant operators. (Section O1.2)

The reactor restart on June 30 was conducted in a conservative, well controlled manner and effective supervision and oversight was noted in addressing equipment performance problems. In contrast, during the July 23 startup, operators energized the normal station service transformer without cooling water. This error was caused, in part, by an inadequate operating procedure and by the operators' poor response to the associated transformer alarm. (Section O1.3)

Several equipment problems associated with the reactor core isolation cooling (RCIC) system were evident during system operation subsequent to the June 24 automatic reactor shutdown at Unit 2. These degraded equipment conditions resulted in the control room staff declaring the RCIC system inoperable per Technical Specifications, but operators were able to compensate for these conditions and successfully operated the system to maintain reactor vessel level. These compensatory actions, collectively, were a distraction to the control room staff during the recovery from the automatic shutdown. (Section O2.1)

During the recovery from the June 24 automatic reactor shutdown, the control room staff operated the reactor core isolation cooling (RCIC) system with the flow controller in manual. The RCIC system operating and alarm response procedures contained some inconsistencies regarding operating the system in this mode, but operators were able to use their system knowledge to adequately maintain reactor vessel level. The licensee's July 13, 1999, evaluation of operator performance adequately identified and resolved the RCIC system operating procedure issues and was reasonably thorough and critical in assessing operator performance. The licensee acknowledged that their process to evaluate operator performance following a major plant event warranted improvements to ensure timely and effective corrective action. (Section O3.1)

The documentation and communication between the crews of the reactor core isolation cooling (RCIC) system controller issues were poor following the June 24 automatic reactor shutdown.

Executive Summary (cont'd)

Specifically, operator logs did not contain any information regarding the RCIC controller problems and the observed problems were not verbally, or in the operator turnover sheets, communicated to the oncoming shift. Additionally, operators exercised poor judgement by placing the RCIC controller in automatic to validate previously confirmed improper system performance. (Section O4.1)

Maintenance

During the conduct of maintenance at Unit 2, a faulty manual control circuit in the feedwater controller failed which resulted in a reactor vessel level transient and caused an automatic reactor shutdown. Plant conditions were acceptable to perform the maintenance. However, the pre-job brief was limited, in that, it did not discuss the potential consequences of a controller failure. (Section M1.1)

A relay failure in the main generator backup protection circuit resulted in a partial loss of off-site power following the automatic reactor shutdown at Unit 2 and additional challenges to plant operators. NMPC's investigation into and identification of the cause was thorough. Although not a direct contributor to the relay failure, the investigation showed that certain recommended substation breaker preventive maintenance was not being performed by the off-site maintenance group. (Section M2.1)

During the June 24 automatic reactor shutdown and again on July 2, the reactor core isolation cooling system injection containment isolation check valves exhibited a number of performance problems. The valves remained operable, but were degraded. Ineffective corrective actions contributed to the valves' poor operating history. Additionally, the installation of a modification to the indicator shaft was not implemented in a timely fashion. (Section M2.2)

During the Unit 2 forced outage, position indication problems with the residual heat removal system containment isolation check valve (AOV39B) were repaired and the valve was tested satisfactorily. Subsequently, AOV39B failed to close when shutdown cooling was secured. Previous poor maintenance practices, including weak valve maintenance procedures contributed to the valve failure. (Section M2.3)

During the June 24 automatic shutdown transient at Unit 2, the reactor core isolation cooling (RCIC) system exhibited 200-300 gallon per minute flow oscillations with the controller in automatic. NMPC investigation showed that the flow controller had not been properly adjusted when it was replaced in 1996, in spite of available industry information on proper controller set-up. The controller out-of-adjustment condition, in conjunction with some air in the flow transmitter sensing lines, caused the flow oscillations. The failure to have appropriate procedures for tuning and calibration of the RCIC system was a non-cited violation and the result of past poor quality maintenance. (Section M3.1)

Following the June 24 automatic reactor shutdown and manual initiation of the reactor core isolation cooling (RCIC) system, operators identified that the lube oil level was not visible in the sight glass. The low oil level was the result of oil not being added following an oil sample being taken. Subsequent lube oil analysis showed that there was no RCIC system degradation. NMPC revised the RCIC oil sample procedure to assure that proper oil level is maintained. (Section M3.2)

Prior to July 2, troubleshooting efforts associated with the reactor core isolation cooling valve repair were poor, in that, logs did not fully reflect work done and the valve status was not adequately communicated to the oncoming shift. This resulted in the determination that the root cause of the problem had been found and that the valve had been repaired, when in fact, it was not. Unit 2 management and staff demonstrated poor judgement by rationalizing the anomalies associated with the valve maintenance as acceptable, rather than thoroughly investigating and resolving them. (Section M4.1)

Prior to the reactor core isolation cooling injection valve failures on July 2, the corrective actions to address valve performance deficiencies were narrowly focused. NMPC subsequently assembled a team which developed the root causes of the poor valve operating history and implemented appropriate corrective actions to resolve the technical problems. (Section M7.1)

Maintenance and engineering staff performance associated with the Anchor/Darling testable check valves was weak. A significant number of position indication problems due to mechanical interferences or mis-adjustments were documented and this negative equipment performance trend was not earlier recognized or evaluated. A timely installation of an approved 1992 modification would have prevented the improper reassembly of the RCIC system injection check valve in 1998. (Section M7.1)

The Unit 2 reactor core isolation cooling system reliability and performance was degraded as a result of weaknesses in maintenance and engineering support. (Section M7.2)

Engineering

NMPC assumptions used to develop the individual plant examination for the frequency of loss of offsite power were not consistent with operating experience. NMPC updated its probabilistic risk analysis model and has submitted a revised individual plant examination to the NRC. (Section E1.1)

The failure rate data evaluation methodology used in the Nine Mile Point Unit 2 probabilistic risk analysis (PRA) for the reactor core isolation cooling (RCIC) system was appropriate. The PRA assumptions regarding the loss of offsite power were consistent with plant operating practices. There was an increase in core damage frequency caused by the RCIC system malfunctions following the April 24, 1999, scram. The availability of multiple redundant systems to provide makeup to the reactor vessel mitigated the risk significance of this event. The RCIC system operation in the manual mode following the June 24 scram had an almost negligible effect on the core damage frequency. However, the aggregate of equipment malfunctions associated with the June 24 scram and the April 24 scram have risk significance and both scrams are being considered for inclusion in the NRC accident sequence precursor program. (Section E2.1)

Executive Summary (cont'd)

Misapplication of industry guidance during the development of the second ten-year interval inservice testing (IST) program at Unit 2 resulted in improperly deleting the requirement to conduct IST testing for 26 safety related valves. The valves were subsequently tested satisfactorily. Failure to conduct the required testing was a non-cited violation. (Section E2.2)

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ATTACHMENTS

Report Details

Summary of Plant Status

Nine Mile Point Unit 1 (Unit 1) returned to power operation on June 17 following the completion of the refuel outage, which was 66 days in duration. During power operation, erratic operation of the turbine control mechanical pressure regulator and electronic pressure regulator was observed. On July 23, Unit 1 automatically shutdown from 100 percent power during testing of the mechanical pressure regulator. Details of the Unit 1 automatic shutdown and associated inspector observations were documented in NRC inspection report 99-07. Unit 1 remained shutdown through the end of this inspection period.

Nine Mile Point Unit 2 (Unit 2) began the period at 100 percent power. On June 24, Unit 2 automatically shutdown due to a faulty feedwater flow controller. On June 30, Unit 2 commenced a reactor startup. The reactor core isolation cooling system valve testing following the startup was unsatisfactory and on July 2, Unit 2 was shutdown to conduct repairs. A 10CFR50.72 notification (Event No. 35889) was made on July 2, 1999, for this event and later retracted on July 29, 1999. The retraction was made because the preliminary determination that the testable check valve indication problems adversely impacted RCIC system operability and containment integrity was subsequently determined to be unfounded. Unit 2 was returned to service on July 23 and reached 100 percent power on July 26, 1999.

I. Operations

O1 Conduct of Operations [1]

O1.1 General Comments (71707)

Using NRC Inspection Procedure 71707, the resident inspectors conducted frequent reviews of ongoing plant operations. The reviews included tours of accessible areas of both units, verification of engineered safeguards features (ESF) system operability, verification of adequate control room and shift staffing, verification that the units were operated in conformance with Technical Specifications (TSs), and verification that logs and records accurately identified equipment status or deficiencies. In general, the conduct of operations was professional and safety-conscious.

O1.2 Automatic Reactor Shutdown Overview (Unit 2)

a. Inspection Scope (71707)

On June 24, at 3:41 p.m., Unit 2 experienced an automatic reactor shutdown (scram) from 100 percent power due to a malfunction in the feedwater master controller. Subsequent to the scram, the reactor core isolation cooling (RCIC) system was declared inoperable due to unexpected RCIC flow oscillations occurring with the flow controller in automatic. The inspectors responded to the control room and observed portions of the

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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.

scram recovery process. The inspectors also reviewed the operator logs, post-scram review documentation, and the sequence of events. Additionally, the event was discussed with Unit 2 operations and management personnel.

b. Observations and Findings

The cause of the transient was low reactor water level due to a failure of the feedwater master controller. Scram recovery was complicated by a partial loss of offsite power (Line 5) and the RCIC system failed to perform correctly in the automatic mode of operation. The cause of the loss of line 5 was the failure of one of the main generator output breaker fault relays. The cause of the RCIC system flow oscillations was a miscalibrated flow controller and air in the flow transmitter sensing lines.

The reactor trip resulted in a main turbine trip on reverse power, as designed. All control rods inserted properly. The turbine trip caused a fast transfer of both 13.8 kilo-volt (kV) buses to offsite power sources. The fast transfer was completed with one 13.8 kV bus transferring to line 5 and the other to line 6. Shortly after the fast transfer of the 13.8 kV buses was complete, the line 5 offsite power source de-energized and the division 1 and 3 emergency diesel generators started on the undervoltage condition and energized their respective buses. The loss of line 5 resulted in tripping the feedwater and condensate booster pumps supplied from that source. The subsequent condensate transient caused the remaining condensate booster and feedwater pumps to trip on low suction pressure.

Prior to the scram, part of the balance of plant electrical system was in an off-normal condition to support planned circuit breaker maintenance. The off-normal electrical line-up resulted in the loss of power to all of the turbine electro hydraulic control (EHC) system pumps and the offgas system. With the loss of EHC system pumps and the off-gas system, the condenser became unavailable as a heat sink (no pressure control using the turbine bypass valves). Accordingly, the safety relief valves were cycled intermittently to control reactor pressure.

Operators manually initiated the RCIC system for reactor vessel level control. The RCIC system exhibited oscillations in automatic and the controller was placed in manual. Operators closed the outboard main steam isolation valves to minimize the cooldown rate and to isolate the condenser which was losing vacuum as a result of the loss of the off-gas system. Excluding the above stated exceptions, operators executed a routine scram recovery and placed the plant in a stable condition.

In accordance with 10 CFR 50.72, the control room staff made appropriate notifications for the June 24, 1999, automatic reactor protection system actuation with a partial loss of off site power (Event No. 35857) and the subsequent RCIC system operability problem (Event No. 35859). The control room staff made an update to Event No. 35857 at 10:44 p.m. on June 24, 1999, notifying the NRC staff that the off site power line 5 had been restored.

c. Conclusions

On June 24, an automatic reactor shutdown from 100 percent power occurred at Unit 2 during maintenance on the feedwater control system. Operators placed the plant in a stable condition; overall, operator performance was adequate. Several equipment performance problems, combined with an off-normal plant electrical lineup, resulted in increased challenges to plant operators.

O1.3 Reactor Startup Observations (Unit 2)

a. Inspection Scope (71707)

The inspectors observed reactor startup activities conducted on June 30 and July 23. This review included the conduct of operations, resolution of plant problems, and observations of management oversight.

b. Observations and Findings

A reactor startup was conducted on June 30. On July 1, 1999 operators raised reactor pressure in preparation to perform the RCIC system injection test at rated pressure. At about 900 psig, operators observed significant control room instrumentation oscillations. Plant evolutions were put on hold pending investigation and resolution of the problem. Troubleshooting efforts were effective in determining that the instrumentation oscillations were caused by steam line resonance. Based upon discussions with the troubleshooting team, the inspectors determined that traveling pressure waves are produced in the main steam and bypass piping whenever the steam flow is disturbed by a valve position change. The pressure waves are reflected back and forth between the reactor vessel and turbine valves. The pressure waves are detected by the EHC pressure transducer and reinforced by the EHC regulator which can result in system oscillations. Operator response to the control room instrumentation oscillations and subsequent troubleshooting efforts was appropriate. The unit was shutdown on July 2, for unrelated RCIC system testable check valve problems. (See section M2.2)

During the July 23 plant startup, the normal station service transformer was energized with the cooling systems secured. The control room annunciator associated with the transformer was in alarm when the transformer was energized. However, control room operators thought that the alarm would clear after the transformer was placed in service. House loads were transferred back to the reserve transformer when the alarm did not clear. NMPC determined that the shutdown procedure had been changed to add a step to secure cooling for the normal station service transformer. However, a similar change was not made to the startup procedure to un-isolate cooling flow.

c. Conclusions

The reactor restart on June 30 was conducted in a conservative, well controlled manner and effective supervision and oversight was noted in addressing equipment performance problems. In contrast, during the July 23 startup, operators energized the normal station service transformer without cooling water. This error was caused, in part, by an inadequate operating procedure and by the operators' poor response to the associated transformer alarm.

O2 Operations Status of Facilities and Equipment

O2.1 RCIC System Performance During the Automatic Reactor Shutdown (Unit 2)

a. Inspection Scope (71707)

During the June 24 scram recovery, the RCIC system was started for vessel level control and exhibited 200-300 gpm flow oscillations while in the automatic flow control mode. Operators declared the system inoperable, but continued to operate RCIC in the manual flow control mode. Additional RCIC system performance problems were observed and compensated for by the control room staff. The inspector reviewed RCIC system performance during the automatic reactor shutdown on June 24 and assessed the impact on plant operators.

b. Observations and Findings

RCIC flow oscillations were observed with the flow controller in automatic. Operators suspected a possible flow controller problem and shifted the controller to manual, where the oscillations stopped. When in manual, the controller maintains a constant RCIC turbine speed. An operator must periodically adjust turbine speed to maintain the desired flow rate and vessel level as reactor pressure changes. In automatic, the flow rate is maintained automatically, regardless of reactor pressure, by adjusting the desired flow via a thumb wheel setting. Thus, the failure of the RCIC system to operate in automatic was not a significant safety problem, but rather an inconvenience to the control room operators because more attention had to be given to the system in manual. (See Section M3.1)

During operation of the RCIC system to maintain reactor vessel level, turbine oil level was observed to be below the lowest level in the sightglass. This did not impact system operability, but was another distraction and operating concern to the control room staff. (See Section M3.2)

The RCIC governor valve indicated full closed during system operation. Nonetheless, operators verified the operation of the RCIC system using other instrumentation (i.e., turbine speed and discharge pressure). The licensee subsequently determined that the valve position limit switch was out of adjustment. It was later adjusted and tested satisfactorily. NMPC discovered that information regarding proper switch adjustment was not provided in the work instructions, as the adjustment was considered to be a "skill of the craft" item. DER 2-1999-2164 was initiated for this issue and the work procedures were enhanced.

The RCIC turbine gland seal compressor tripped after running for several hours. The loss of compressor resulted in some gland seal leakage from the turbine shaft, but did not significantly impact RCIC system operation. Subsequent maintenance staff troubleshooting identified that the starter coil was defective and it was replaced.

During operation and shutdown of the RCIC system, valve position indication problems were noted with the two testable check valves located in the injection line to the reactor vessel. (See Section M2.2)

c. Conclusions

Several equipment problems associated with the reactor core isolation cooling (RCIC) system were evident during system operation subsequent to the June 24 automatic reactor shutdown at Unit 2. These degraded equipment conditions resulted in the control room staff declaring the RCIC system inoperable per Technical Specifications, but operators were able to compensate for these conditions and successfully operated the system to maintain reactor vessel level. These compensatory actions, collectively, were a distraction to the control room staff during the recovery from the automatic shutdown.

O3 Operations Procedures and Documentation

O3.1 Operator Scram Response and Use of RCIC Operating Procedures (Unit 2)

a. Inspection Scope (71707)

The inspector reviewed the actions taken by operators to control vessel level and to compensate for RCIC flow oscillations with the flow controller in automatic. The inspector reviewed instrument and control procedures for maintaining the RCIC speed/flow control system, operating procedures used to control the system, and the emergency operating procedures. The inspector also reviewed the licensee's assessment of operator performance, dated July 13, 1999.

b. Observations and Findings

The inspectors observed that operators responded properly to lowering reactor vessel water level by initiating the RCIC system. However, independent inspector review of the RCIC system operating procedure (OP) and associated alarm response procedures identified some apparent inconsistencies, including:

1) The OP did not discuss the manual mode of RCIC system flow control. The OP did describe RCIC system control of reactor vessel level via opening or closing the recirculation line back to the condensate storage tank, and by adjusting flow via the controller in automatic.

2) The OP did not address bypassing the reactor vessel high water level isolation (level 8). Additionally, the alarm response procedure (for operator actions when a level 8 isolation of the RCIC system occurs) did not address restart of the RCIC system until a reactor vessel level 2 condition was satisfied.

3) The OP method of starting the RCIC system in the manual mode calls for opening the steam admission valve, allowing the machine to start and pump water through the minimum flow valve, and then opening up the injection valve. The OP does not address starting/restarting the system using the manual start pushbutton.

In addition, based upon inspector review of the post-trip alarm printer and discussions with the plant staff, it appeared that control room operators experienced some difficulty in following the OP and had to rely upon systems knowledge to adequately control vessel level. For example, the system was secured by closing the steam admission valve and then the injection valve. When operators restarted the system, they were not alerted to the 10 second time delay (TD) interlock between opening of the steam admission valve and then the injection valve. From review of the printout, there were several instances where the injection valve got an open signal while the TD was still in effect.

NMPC's initial post-transient evaluation was conducted prior to the Unit 2 restart on June 30. The evaluation was sufficient to identify the cause of the scram and to identify and address major equipment problems prior to unit restart. Based upon a number of discussions between the NRC staff and NMPC prior to and following the July 2 shutdown, the licensee initiated a detailed evaluation focused on operator performance during the recovery from the June 24 scram. At the August 23, 1999, exit meeting, the licensee acknowledged that their process to evaluate operator performance following a major plant event warranted improvements to ensure timely and effective corrective action.

The inspectors reviewed the detailed operator performance evaluation, dated July 13, 1999, and concluded that the procedural issues discussed above were adequately addressed and that the licensee's detailed assessment of operators' performance was acceptable. Some of the particular RCIC system operating information was lost due to the strip chart recorder failure part-way through the scram recovery period.

c. <u>Conclusions</u>

During the recovery from the June 24 automatic reactor shutdown, the control room staff operated the reactor core isolation cooling (RCIC) system with the flow controller in manual. The RCIC system operating and alarm response procedures contained some inconsistencies regarding operating the system in this mode, but operators were able to use their system knowledge to adequately maintain reactor vessel level. The licensee's July 13, 1999, evaluation of operator performance adequately identified and resolved the RCIC system operating procedure issues and was reasonably thorough and critical in assessing operator performance. The licensee acknowledged that their process to evaluate operator performance following a major plant event warranted improvements to ensure timely and effective corrective action.

O4 Operator Knowledge and Performance

O4.1 Event Log-keeping and Shift Turnover (Unit 2)

a. Inspection Scope (71707)

The inspector reviewed the operators' response to the June 24 automatic reactor shutdown, including examination of operator logs and shift turnover information.

b. Observations and Findings

In review of the operator/system response to the transient the inspectors found that:

- Control room logs were very poor, as there was no discussion of any RCIC problems that were evident in the initial response to the event. Specifically there was no discussion of taking the flow controller to manual, although subsequently a deficiency event report (DER) was written.

- The turnover of information from the first crew to the second crew was poor. The station shift supervisor (SSS) for the second crew involved did not know the extent of the RCIC system oscillations. As a result, the RCIC controller was again placed in automatic to observe system operation to validate the DER information.

c. Conclusions

The documentation and communication between the crews of the reactor core isolation cooling (RCIC) system controller issues were poor following the June 24 automatic reactor shutdown. Specifically, operator logs did not contain any information regarding the RCIC controller problems and the observed problems were not verbally, or in the operator turnover sheets, communicated to the oncoming shift. Additionally, operators exercised poor judgement by placing the RCIC controller in automatic to validate previously confirmed improper system performance.

08 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-410/99-10: Unit 2 Reactor Trip due to a Feedwater Master Controller Failure.

The technical details associated with this LER are discussed in this NRC inspection report. The inspector completed an on-site review of the LER and verified that it was completed in accordance with the requirements of 10CFR50.73. Specifically, the description and analysis of the event, as contained in the LER were consistent with the inspectors' understanding of the event. The root cause and corrective and preventive actions as described in the LER were reasonable. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Feedwater Flow Controller Failure (Unit 2)

a. Inspection Scope (62707)

Due to some problems being experienced with the leading edge flow meter, NMPC elected to perform maintenance on the feedwater control system. In preparation, operators placed the feedwater master flow controller in manual. When the master flow controller was switched from automatic to manual, a feedwater transient occurred and resulted in an automatic reactor shutdown. The inspector reviewed the work planning and discussed the conduct of the maintenance with NMPC personnel.

b. Observations and Findings

Maintenance technicians were preparing to flush the feedwater flow instrument lines in accordance with a work order package. To support the work, operators prepared to shift the feedwater level control system from three-element to single-element control by shifting the master controller to manual. Immediately after this step was performed, the controller output dropped to zero and the feedwater level control valves started to close. The operator was not able to stabilize level and an automatic reactor shutdown occurred. A faulty manual control card was found in the feedwater master flow controller logic circuit and was replaced.

The work to be conducted was not previously scheduled and therefore was not part of the normal work control process. However, the work was planned and implemented through the fix-it-now (FIN) team in conjunction with the control room operators. A work impact assessment was performed and it was determined that there were no procedural restrictions in performing the work and a pre-job brief was conducted. It was noted that the pre-job brief did not specifically discuss the potential adverse consequences of a controller failure. NMPC has taken corrective actions to heighten the sensitivity of workers and management conducting evolutions that have the potential to cause transients.

c. Conclusions

During the conduct of maintenance at Unit 2, a faulty manual control circuit in the feedwater controller failed which resulted in a reactor vessel level transient and caused an automatic reactor shutdown. Plant conditions were acceptable to perform the maintenance. However, the pre-job brief was limited, in that, it did not discuss the potential consequences of a controller failure.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Loss of One Source of Off-site Power (Line 5) (Unit 2)

a. Inspection Scope (62707)

The June 24 automatic reactor shutdown caused a turbine trip which initiated relays to transfer station buses to 115 kV offsite power sources (lines 5 and 6). NMPC determined that a failure in the main generator breaker backup protection circuit, located in an off-site substation, resulted in the loss of line 5. The inspectors reviewed NMPC's troubleshooting and evaluation methods used to determine the cause of the loss of line 5, as documented in DER 2-1999-2158, and discussed the event with NMPC personnel.

b. Observations and Findings

NMPC is provided with two offsite power sources from the transmission network to the onsite distribution system and three divisions of on-site power. When line 5 was lost, both division I and division III were aligned to line 5. On the loss of line 5, the undervoltage relays on both division I and III initiated and started both emergency diesel generators which successfully re-energized both buses. Due to an off-normal electrical lineup for the balance of plant equipment, the loss of line 5 also caused the loss of additional loads which normally would not have been lost. (See section O1.2)

The circuit failure was isolated to a malfunction with the backup protection circuits for the main generator output breaker. NMPC determined that the apparent cause was that either the breaker auxiliary contacts did not operate properly or a relay failed to operate, resulting in the trip of the feeder breaker to line 5. Initial corrective action included the replacement of the suspected relays and the breaker contacts were moved to the spare contacts. The electrical system was subsequently tested satisfactorily. Subsequent bench testing demonstrated that the root cause was the failure of the suspected relay.

NMPC's investigation into the loss of line 5 determined that there was some Scriba Substation breaker preventive maintenance that had not been performed. Additionally, the quality of maintenance activities in the substation was poor and the interface between the off-site and on-site maintenance organizations was lacking. DER 2-1999-2206 was initiated to address these concerns. The breaker vendor manual showed that the auxiliary switch mechanism and contacts should undergo periodic maintenance and checks. Previous maintenance report checklists identified that these checks were not made. The required maintenance was completed during the troubleshooting and inspection process and additional corrective actions to improve reliability were being evaluated by NMPC. NMPC concluded that the lack of preventive maintenance did not contribute to the relay failure.

c. Conclusions

A relay failure in the main generator backup protection circuit resulted in a partial loss of off-site power following the automatic reactor shutdown at Unit 2 and additional challenges to plant operators. NMPC's investigation into and identification of the cause was thorough. Although not a direct contributor to the relay failure, the investigation showed that certain recommended substation breaker preventive maintenance was not being performed by the off-site maintenance group.

M2.2 Reactor Core Isolation Cooling Injection Containment Isolation Check Valve Failures (Unit 2)

a. Inspection Scope (62707, 37551)

The inspectors observed RCIC valve maintenance activities including disassembly, reassembly, and post maintenance testing and reviewed the NMPC root cause analysis report.

b. Observations and Findings

During the June 24 automatic reactor shutdown, the RCIC system was used to control reactor vessel level. During the RCIC system operation, the injection outboard containment isolation check valve, 2ICS*AOV156 (AOV156) indicated open with no flow (valve should indicate closed) and the injection inboard containment isolation check valve, 2ICS*AOV157 (AOV157) indicated closed with full flow. Maintenance was conducted on AOV156 and AOV157 and initial post-maintenance testing showed that the valves operated satisfactorily. (See Section M4.1)

On July 2, the RCIC system was tested by injecting into the reactor vessel. Once again, AOV157 indicated closed under full system flow conditions. When the RCIC system was secured following testing, AOV156 again failed to indicate closed. Because these observed conditions were similar to those observed on June 24, and it was apparent that previous corrective action were not effective, the reactor was shutdown to determine the root cause and implement appropriate corrective action. NMPC assembled a team to analyze and address the check valve failures and a root cause/investigation plan was developed. (See Section M7.1)

AOV156 Failure to Indicate Closed

NMPC initiated DER 2-1999-2264 to document the AOV156 failure to close event. AOV156 was disassembled and several valve internal discrepancies were identified. For example: mechanics noted that total tolerances for axial shaft component stack-up were outside the acceptance criteria; the indicator side stuffing box was not making metal to metal contact; and the hinge arm length was incorrect. The NMPC team determined that the shutting force was not sufficient to overcome the combination of check valve component out-of-tolerances, packing friction, and limit switch resistance forces. However, the valve was able to function in the open direction and NMPC engineering calculations demonstrated that shutting forces in the event of a steam line break would be sufficient to cause the valve to go closed.

AOV157 Failure to Indicate Open

NMPC initiated DER 2-1999-2161 to document the AOV157 discrepancy. AOV157 was disassembled and several valve internal discrepancies similar to the problems with AOV156 were identified. In addition, the indicator shaft was installed 180 degrees out of position, in the wrong recessed slot on the hinge arm. During the June 1998 outage, the position indicating shaft was removed and incorrectly re-installed. Contributing to the reassembly error was insufficient guidance in the work order. In addition, a 1992 modification to upgrade the indicator shaft to a design that would prevent improper re-assembly was issued, but not installed. The NMPC staff concluded that timely installation of the modification would have prevented the improper re-assembly of the valve. (See Section M7.1)

c. Conclusions

During the June 24 automatic reactor shutdown and again on July 2, the reactor core isolation cooling system injection containment isolation check valves exhibited a number of performance problems. The valves remained operable, but were degraded. Ineffective corrective actions contributed to the valves' poor operating history. Additionally, the installation of a modification to the indicator shaft was not implemented in a timely fashion.

M2.3 Residual Heat Removal System Containment Isolation Check Valve Failure (Unit 2)

a. Inspection Scope (62707)

The residual heat removal system containment isolation check valve, RHS*AOV39B, (AOV39B) did not initially close when shutdown cooling was secured on July 10. The inspector observed portions of the maintenance activities, including post-work testing, and reviewed the corrective actions.

b. Observations and Findings

During the forced outage, position indication cam physical interferences for AOV39B were repaired and the valve was tested satisfactorily on July 8. On July 10, the valve failed to close when shutdown cooling (SDC) flow was throttled and then secured. AOV39B was disassembled and the overall material condition was determined to be poor; with significant galling, nicks, and scratches observed. The valve had been rebuilt during the 1998 refueling outage. Since then, AOV39B has experienced position indication problems and one event, in May 1999, where it did not fully close when SDC was secured. At that time, the limit switches were adjusted and the valve operation was tested satisfactorily.

AOV39B was completely overhauled during this outage, including many new components (i.e., new position indication and actuator shafts). Significant difficulty was experienced during the valve maintenance which required two subsequent rework evolutions. The reworks were caused, in part, by improper re-assembly of the valve (resulting in the valve binding). In addition, NMPC determined that the generic maintenance procedure was not sufficient to address the special considerations required to properly maintain the valve. The failure was considered a maintenance preventable functional failure.

c. Conclusions

During the Unit 2 forced outage, position indication problems with the residual heat removal system containment isolation check valve (AOV39B) were repaired and the valve was tested satisfactorily. Subsequently, AOV39B failed to close when shutdown cooling was secured. Previous poor maintenance practices, including weak valve maintenance procedures contributed to the valve failure.

M3 Maintenance Procedures and Documentation

M3.1 RCIC Flow Oscillations (Unit 2)

a. Inspection Scope (62707)

As previously discussed in Section O2.1, the RCIC system was started for level control and exhibited 200-300 gpm flow oscillations while in automatic. Operators declared the system inoperable and continued to use it in manual. The cause of the oscillations was determined to be improper adjustment for the flow controller. Additionally, air in the flow transmitter sensing lines contributed to the oscillations. The inspector reviewed vendor manual information and maintenance procedures.

b. Observations and Findings

NMPC implemented a work order to troubleshoot, repair, and bench calibrate the controller. The flow transmitter was found to have entrained air and the controller did not have the derivative properly nulled. The RCIC flow controller settings include gain, integral, and derivative. Derivative is used for anticipatory control and, for the RCIC system, should be nulled.

The controller had been replaced in 1996 and was set up to match the replaced controller. Due to the poor quality of the maintenance planned and performed in 1996, controller settings were not documented and the system response was not checked. Industry information was available which provided current procedures for calibration of the turbine control systems and stated that when a controller is replaced, the use of previous controller settings and dynamic testing in the surveillance test mode can be an inaccurate means of controller tuning. Additionally, actual testing (vessel injection) may be needed to assure proper response. This industry information was not used. On July 2, Unit 2 completed the injection test to the reactor vessel satisfactorily. The inspector noted that command and control for the test was excellent. There did not appear to be any flow oscillations on the initial startup or following the step change demand signals initiated using the controller. However, deficiencies were identified with the injection check valve position indication. (See Section M2.2)

The failure to have appropriate procedures to ensure proper performance and documentation of all required RCIC system tuning and calibration is a violation of 10CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings". This severity level IV violation is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy (**NCV 50-410/99-06-01**). This violation is in the licensee's corrective action program as DER 2-1999-2153.

c. Conclusions

During the June 24 automatic shutdown transient at Unit 2, the reactor core isolation cooling (RCIC) system exhibited 200-300 gallon per minute flow oscillations with the controller in automatic. NMPC investigation showed that the flow controller had not been properly adjusted when it was replaced in 1996, in spite of available industry information on proper controller set-up. The controller out-of-adjustment condition, in conjunction with some air in the flow transmitter sensing lines, caused the flow oscillations. The failure to have appropriate procedures for tuning and calibration of the RCIC system was a non-cited violation and the result of past poor quality maintenance.

M3.2 RCIC Turbine Low Oil Level (Unit 2)

a. Inspection Scope (62707)

During the June 24 automatic reactor shutdown, when the RCIC turbine was started, oil levels on the sight glass were not visible. The inspector reviewed NMPC's corrective actions to address this issue.

b. Observations and Findings

RCIC turbine operation was not affected by the low oil level and bearing temperature remained satisfactory. No low lube oil pressure or bearing high temperature alarms were observed during RCIC system operation with this condition. As a precaution, the RCIC lube oil was sampled and the analysis showed that no degradation occurred.

The licensee determined that the low oil level was caused by improper oil sampling processes. The chemistry department obtained a two liter oil sample at the drain valve on the oil cooler following the last RCIC system quarterly surveillance test and the procedure did not require the replenishment of oil following the sample. The licensee also identified that the vendor manual recommended that lube oil level be checked after each turbine run. The quarterly surveillance procedure and operating procedure did not have this step. The procedures were changed to assure that proper lubrication oil level is maintained. This minor violation is not subject to enforcement action.

c. Conclusions

Following the June 24 automatic reactor shutdown and manual initiation of the reactor core isolation cooling (RCIC) system, operators identified that the lube oil level was not visible in the sight glass. The low oil level was the result of oil not being added following an oil sample being taken. Subsequent lube oil analysis showed that there was no RCIC system degradation. NMPC revised the RCIC oil sample procedure to assure that proper oil level is maintained.

M4 Maintenance Staff Knowledge and Performance

M4.1 Poor Maintenance Staff Performance Associated with RCIC Check Valve Troubleshooting (Unit 2)

a. Inspection Scope (62707)

During the RCIC system operation on June 24, AOV156 indicated open with no flow (valve should indicate closed) and AOV157 indicated closed with full flow. Maintenance was conducted on AOV156 and 157 and post-maintenance testing showed that the valves operated satisfactorily. The work that was conducted focused on the external position indication mechanisms. Subsequently, on July 2, during the RCIC injection test, the valves exhibited indication problems and the reactor was shutdown to conduct troubleshooting. The inspector observed the initial AOV156 troubleshooting efforts and discussed activities with NMPC personnel.

b. Observations and Findings

On June 28, the maintenance day shift crew that was working on AOV156 was relieved by the night shift crew. The day shift crew had left the bearing bracket cap screws reinstalled finger tight, which was not relayed to the night shift crew. The day shift crew had not been able to get the valve to stroke without assistance. The night shift crew found that the bearing bracket cap screws were rubbing against the bearing bracket (as they were only finger tight) and concluded that was the cause for the inability for the valve to operate properly. After tightening the cap screws, the valve operated acceptably. The next day, the day shift crew supervisor expressed reservations that the cap screws being finger tight was the root cause. After several discussions were held with engineering and management personnel, the root cause was not challenged further. Subsequently on July 2, the valve failed to close when the RCIC system was secured. (See Section M2.2)

The inspectors observed that there were several causes for deciding that the valve had been repaired when, in fact, it had not. Troubleshooting efforts were focused on external not internal valve problems and the troubleshooting work order was not specific. A written turnover log was not adequately maintained to capture the troubleshooting efforts. Although the day shift supervisor had reservations and challenged the situation, NMPC management failed to properly recognize and resolve the concerns.

c. Conclusions

Prior to July 2, troubleshooting efforts associated with the reactor core isolation cooling valve repair were poor, in that, logs did not fully reflect work done and the valve status was not adequately communicated to the oncoming shift. This resulted in the determination that the root cause of the problem had been found and that the valve had been repaired, when in fact, it was not. Unit 2 management and staff demonstrated poor judgement by rationalizing the anomalies associated with the valve maintenance as acceptable, rather than thoroughly investigating and resolving them.

M7 Quality Assurance in Maintenance Activities

M7.1 Review of Check Valve Corrective Action Team Activities (Unit 2)

a. Inspection Scope (62707)

As briefly discussed in Section M2.2, the corrective actions taken by NMPC to resolve RCIC system check valve problems following the June 24 scram were not effective. After the RCIC system full flow testing injection valve failures on July 2, Unit 2 was shutdown and a multi-discipline team was assembled to investigate the causes of the RCIC containment isolation check valve failures, to determine the extent of condition, and to implement corrective actions. The inspector observed team activities and reviewed the team's root cause analysis report.

b. Observations and Findings

The inspector noted that the team developed a plan and maintained an activity log. The RCIC check valves were quarantined to identify the "as found" condition for the failure analysis. A vendor representative was available to assist with on-site investigation and corrective maintenance. The scope was appropriately expanded to include other Anchor Darling (A/D) testable check valves with remote position indication. These valves were located in the high pressure core spray, low pressure core spray, residual heat removal, and feedwater systems. Nine containment isolation valves were included in the scope.

A historical review showed that there had been no occurrences of valves failing to open, but several instances of the valves failing to fully close. Additionally, a significant number of position indication problems due to mechanical interferences or mis-adjustments were documented and a long history of packing leakage problems was noted. It was evident that this negative performance trend of valve problems was not earlier recognized or evaluated by the maintenance or engineering staffs. A modification to the valve position indication stem was issued in 1992, but was not installed. This modification was designed to prevent the error made during the 1998 outage work on the RCIC injection check valve, which resulted in the position indication shaft being incorrectly installed. The licensee's investigation team also identified that a modification to eliminate the position indication limit switches was proposed in 1991, but was closed and not implemented.

The inspector observed that the corrective actions developed by the team were extensive and included addressing negative personnel performance aspects of maintenance and engineering staffs. The inspector noted that NMPC intends to install a modification to eliminate the limit switches for Anchor/Darling testable check valves.

c. Conclusions

Prior to the reactor core isolation cooling injection valve failures on July 2, the corrective actions to address valve performance deficiencies were narrowly focused. NMPC subsequently assembled a team which developed the root causes of the poor valve operating history and implemented appropriate corrective actions to resolve the technical problems.

Maintenance and engineering staff performance associated with the Anchor/Darling testable check valves was weak. A significant number of position indication problems due to mechanical interferences or mis-adjustments were documented and this negative equipment performance trend was not earlier recognized or evaluated. A timely installation of an approved 1992 modification would have prevented the improper reassembly of the RCIC system injection check valve in 1998.

M7.2 RCIC Maintenance/Performance Summary (Unit 2)

a. Inspection Scope, Observations and Findings (71707)

Due to the problems identified during the June 24 automatic reactor shutdown, the inspectors summarized a brief history of the recent RCIC system performance issues:

- The RCIC system failed on demand during the April 24, 1999 automatic reactor shutdown. The failure occurred because the turbine trip valve was not properly adjusted. (See NRC inspection report 99-04)

- Numerous minor RCIC support system discrepancies. (See Section O2.1)

- The RCIC system injection check valves have had a history of position indication problems (See Section M7.1).

- Several maintenance related deficiencies were found during the RCIC system planned work window from May 11-22 (See NRC inspection report 99-05).

- In June 1999, the RCIC system was placed in the maintenance rule category (a)(1).

b. Conclusions

The Unit 2 reactor core isolation cooling system reliability and performance was degraded as a result of weaknesses in maintenance and engineering support.

III. Engineering

E1 Conduct of Engineering

E1.1 Individual Plant Examination Assumptions Associated with Loss of Offsite Power (Unit 2)

a. Inspection Scope (37551)

The inspector reviewed the Unit 2 individual plant examination (IPE) and probabilistic risk analysis model associated with the loss of offsite power, and held discussions with NMPC personnel.

b. Observations and Findings

The inspector noted that, prior to the June 24 event, there have been nine losses of offsite power (LOSP) at Unit 2, seven of which occurred between December 1988 and November 1993. The majority of these events were caused by component failure, with others associated with work control practices.

The inspector reviewed the NMPC safety and availability assessment of Line 5 and 6 probabilistic risk analysis (PRA) treatment report, dated August 6, 1999. The assumptions used in the initial PRA regarding loss of offsite power were not consistent with NMPC operating experience. The initiating event frequency used in the initial PRA for loss of lines 5 and 6 is 0.04 events per year per line. The actual frequency of these events is a much higher 0.33. The impact of this increased number of initiators since the initial IPE contributed to an increase in the core damage frequency (CDF) from 3.1E-05/yr to 5.4E-05/yr. NMPC updated their PRA and has submitted a revised IPE to the NRC.

c. Conclusions

NMPC assumptions used to develop the individual plant examination for the frequency of loss of offsite power were not consistent with operating experience. NMPC updated its probabilistic risk analysis model and has submitted a revised individual plant examination to the NRC.

E2 Engineering Support of Facilities and Equipment

E2.1 Reactor Core Isolation Cooling System Failure Safety Significance Review (Unit 2)

a. Inspection Scope (37551)

The Region I Senior Reactor Analysts (SRAs) reviewed portions of the Unit 2 individual plant examination (IPE), probabilistic risk analysis (PRA) model, and the licensee's event evaluations to assess the significance of RCIC system malfunctions noted during the April 24 and June 24, 1999, automatic reactor shutdowns (scrams). The items specifically reviewed were the method used to determine the RCIC pump failure probability data, PRA assumptions regarding the mitigation of loss of offsite power events and the risk associated with the RCIC system malfunctions following the two reactor scrams.

b. Observations and Findings

The SRAs found that the licensee's component failure rate practice was appropriate and consistent with current industry practice. The Unit 2 IPE does not specifically model the failure probabilities of the RCIC turbine protective devices. The failure of the protective devices, if they result in the failure of RCIC, would be appropriately included in the RCIC failure rate data. The practice of collapsing the failure of "sub-components" into "super-components" is routinely performed to simplify the PRA data collection and evaluation process. This practice does not adversely affect the quality or accuracy of the PRA. On a periodic basis, the PRA failure rate data is updated based on actual plant equipment performance. The SRAs confirmed with the licensee's PRA staff that the recent RCIC system failures would be evaluated during the next Unit 2 PRA failure rate data update.

The SRAs reviewed the Unit 2 methodology for coping with a loss of offsite power (LOSP) events. Nine Mile Point Unit 2 has two emergency diesel generators (EDGs) that power necessary mitigation equipment if offsite power is lost. The failure of multiple trains of redundant safety-related equipment must occur to result in a loss of all normal and emergency alternating current (AC) power sources. Therefore, the frequency of a loss of offsite AC power, concurrent with the failure of both trains of the emergency diesel generators, is low. However, if offsite power and both EDGs were unavailable, the current PRA model allows operation of the RCIC system to provide reactor vessel makeup, during the first two hours following event initiation. If the RCIC system were to fail following this initial two-hour interval, reactor vessel level could be maintained by depressurizing the reactor and using the diesel-driven fire water pump to provide reactor vessel inventory makeup. The SRAs noted that while the IPE did not take credit for the availability of the high pressure core spray (HPCS) system for coping with a loss of power, the current PRA does credit the HPCS dedicated diesel generator. Procedural guidance has been provided to the operators to cross-tie one of the Division I or II electrical buses to the HPCS diesel generator bus (Division III) to ensure adequate HPCS emergency diesel generator cooling (via a Division I or II service water pump), to power a battery charger, and to provide low pressure injection. Ultimately an AC power source (one off site or either of the Division I or II emergency diesel generators, or Division III crosstie) must be recovered, before station battery depletion, for any of the LOSP sequences to be successful.

Following the April 24, 1999, automatic reactor shutdown, both offsite power sources and the emergency diesel generators remained available. While RCIC failed to operate following this event, HPCS was available and provided high pressure reactor vessel makeup. The power conversion system (feedwater and condensate systems) automatically secured, as design, following the slow non-safety related bus transfer. However, the system remained available and was subsequently recovered following the event. In addition, the automatic depressurization system and the multiple low pressure injection pumps also remained available in the event that the high pressure injection sources failed.

Following the June 24 automatic shutdown, one of the offsite power supplies (line 5) was unavailable which caused the partial loss of non-safety related loads and the temporary loss of power to the Division I and III emergency electrical busses. Power was restored to the safety related busses. The availability of the feedwater and condensate systems was partially degraded by the loss of line 5, but remained recoverable. The HPCS remained available following this event. The manual initiation of the RCIC system was in accordance with station procedures. Although the RCIC system was not operated with the pump controller in automatic, the system maintained reactor vessel level in the manual mode.

c. Conclusions

The failure rate data evaluation methodology used in the Nine Mile Point Unit 2 probabilistic risk analysis (PRA) for the reactor core isolation cooling (RCIC) system was appropriate. The PRA assumptions regarding the loss of offsite power were consistent with plant operating practices. There was an increase in core damage frequency caused by the RCIC system malfunctions following the April 24, 1999, scram. The availability of multiple redundant systems to provide makeup to the reactor vessel mitigated the risk significance of this event. The RCIC system operation in the manual mode following the June 24 scram had an almost negligible effect on the core damage frequency. However, the aggregate of equipment malfunctions associated with the June 24 scram and the April 24 scram have risk significance and both scrams are being considered for inclusion in the NRC accident sequence precursor program.

E2.2 Active Valves Not Included In the Inservice Testing Program (Unit 2)

a. Inspection Scope (37551)

On July 19, Unit 2 identified that 26 valves had been improperly excluded from the inservice testing (IST) program. The inspector reviewed the DER, American Society of Mechanical Engineers (ASME) requirements and discussed the issue with NMPC personnel.

b. Observations and Findings

The 26 valves were associated with residual heat removal, reactor core isolation cooling and high pressure core spray system. The valves are normally closed, but do have an active safety function and are therefore required to be in the IST program.

The valves were deleted from the IST program when the second ten-year interval of the program superseded the first ten-year interval, in 1998. NMPC performed an extent of condition review and reviewed other changes made to the second ten-year interval. No other problems were identified. The 26 valves were subsequently tested satisfactorily. The Unit 1 IST program plan was reviewed for similar discrepancies and none were found. NMPC determined the cause to be the misapplication of industry guidance concerning IST requirements for active and passive valves.

The failure to conduct the required ASME code inspections is a severity level IV violation and is being treated as a Non-Cited Violation, consistent with Appendix C of the NRC Enforcement Policy **(NCV 50-410/99-06-02)**. This violation is in the licensee's corrective action program as DER 2-1999-2423. The inspector noted that NMPC has recently identified similar ASME Code, Section XI, discrepancies. These discrepancies were documented in LER 99-09, Nonconformance with Technical Specification Regarding ASME Section XI Class 2 Check Valve Reverse Flow Testing. Additional IST and inservice inspection (ISI) program discrepancies were identified and documented by NMPC in LERs 99-07 and 99-08. NMPC has identified these 26 valve testing discrepancies through their ongoing efforts to identify and correct ISI/IST program oversights.

c. Conclusions

Misapplication of industry guidance during the development of the second ten-year interval inservice testing (IST) program at Unit 2 resulted in improperly deleting the requirement to conduct IST testing for 26 safety related valves. The valves were subsequently tested satisfactorily. Failure to conduct the required testing was a non-cited violation.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on August 23, 1999. Richard Crlenjak, Deputy Director, DRP, and Michele Evans, Branch Chief, Projects Branch 1, DRP, attended the exit meeting and held discussions with NMPC managers on site. The licensee acknowledged the inspectors' findings and noted that no proprietary information was identified.

X2 June 25, 1999, Management Meeting

On June 25, 1999, NMPC management met with the NRC staff in the NRC Region I Office in King of Prussia, Pennsylvania, to review recent improvement initiatives. A copy of NMPC's handout (Enclosure 2) and a list of attendees is attached (Enclosure 3).

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

D. Bosnic	Manager, Operations, Unit Two
S. Doty	Manager, Maintenance, Unit One
N. Paleologos	Plant Manager, Unit Two
F. Fox	Acting Manager, Maintenance, Unit Two
R. Smith	Plant Manager, Unit One
N. Rademacher	Manager, Quality Assurance
D. Topley	Manager, Operations, Unit One

INSPECTION PROCEDURES USED

IP 37550	Engineering
IP 37551	On-Site Engineering
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support
IP 90712	In-Office Review of Written Reports of Non-Routine Events at Power Reactor Facilities
IP 92700	Onsite Follow-up of Written Reports of Non-Routine Events at Power Reactor Facilities

ITEMS OPENED, CLOSED, AND UPDATED

OPENED and CLOSED

50-410/99-06-01	NCV	Failure to have appropriate procedures to ensure proper performance and documentation of all required RCIC system tuning and calibration.
50-410/99-06-02	NCV	A misapplication of ASME code requirements for inservice testing (IST) program resulted in deletion of 26 valves from the IST program

CLOSED

50-410/99-10	LER	Unit 2 Reactor Trip due to a Feedwater Master Controller Failure

LIST OF ACRONYMS USED

AC	Alternating Current
A/D	Anchor/Darling
ASME	American Society of Mechanical Engineers
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DC	Direct Current
DER	Deviation/Event Report
EDG	Emergency Diesel Generators
EHC	Electro-hydraulic Control
FIN.	Fix-It-Now
ESF	Engineered Safeguards Feature
HPCS	High Pressure Core Spray
IPE	Individual Plant Examination
IR	Inspection Report
ISI	In-Service Inspection
IST	In-Service Testing
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOSP	Loss of Off-site Power
NCV	Non Cited Violation
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission
OP	Operating Procedure
PRA	Probability Risk Analysis
QA	Quality Assurance
RCA	Radiological Controlled Area
RCIC	Reactor Core Isolation Cooling
SDC	Shutdown Cooling
SRV	Safety Relief Valve
SRA	Senior Reactor Analyst
SSS	Station Shift Supervisor
TD	Time Delay
TS	Technical Specification
USAR	Updated Safety Analysis Report
Unit 1	Nine Mile Point Unit 1
Unit 2	Nine Mile Point Unit 2
WO	Work Order

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Improvement Initiatives

June 25, 1999

Niagara Mohawk

Agenda

Opening Remarks	John Mueller Senior Vice President and Chief Nuclear Officer
Background of Improvement Initiatives	Carl Terry Vice President Nuclear Safety Assessment and Support
On-Going Initiatives and Results	John Conway Vice President Nuclear Generation
Leadership Academy	Jane LeClair, Ed.D. General Supervisor Training Services
	Terry Bockman Unit One Chief Shift Operator
Safety Conscious Work Environment	Ron Hall Director Human Resources
	Michael Briggs Quality Assurance Technician
Corrective Action Program	John Conway
Closing Remarks	John Mueller

Background

- 1997 Employee Survey Results
  - Leadership rated the lowest of the six Critical Success Factors.
  - Many comments on effectiveness of senior and branch management, particularly alignment.
- Early Decisions
  - Leadership was key to attain the next level of human performance at Nine Mile Point.
  - Senior Management to be directly involved in leading the transformation.

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Background

- 1998 Actions
  - Modified One Day Leadership Training
    - Taught by Vice Presidents of Generation and Engineering
    - Key Training Elements
      - » ***Shared leadership***
      - » ***Leadership behaviors***
      - » ***Personal and organizational results*** through ***effective*** leadership

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Background

- Six Leadership Behaviors
  - Gives feedback
  - Takes initiative
  - Displays courage
  - Shows teamwork
  - Provides followup
  - Takes ownership

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Background

- Business changes - 1998
  - Added initiatives for human performance and corrective action
  - Implemented employee survey - perceptions of people at different levels
- 1999 Business Planning changes
  - Simple vision - "Highly Valued People Operating Highly Valued Assets"
  - Strategic direction from executive team
  - Teams formed to implement strategic initiatives

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On-Going Initiatives and Results

- Human Performance - Corrective Action Survey
- Current Initiatives
- Performance Measures

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Human Performance - Corrective Action Survey

- Designed to measure two parameters critical to improving overall station performance
  - Leadership effectiveness in creating an environment conducive to achieving excellent human performance
  - Organizational attitude toward the corrective action program
- Survey implemented in June, October, December 1998
- Survey to be implemented in June, December 1999
- Results are trended over time
- Results influence management incentive compensation

Survey Results

- June 1998 Baseline Results

  - Employees understood expectations and reinforce them
  - Accountability for high standards is consistent
  - Management communication and engagement with employees was weak
  - The DER program was viewed as an effective means of problem identification
  - DERs associated with human performance were viewed by some as punitive
  - Reluctance to initiate DERs was associated with workload and efficiency
  - Extensive written feedback was provided

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Survey Results

- December 1998 Results
  - Almost every question showed improvement
  - Most significant improvement occurred in the weakest areas
    - communication with employees
    - receptivity of management to having decisions questioned
    - attitude of management towards DERs
    - ease and effectiveness of DER process

Current Initiatives

- Corrective Action
- Human Performance
  - Awareness Training
  - Communication and Recognition
  - Work Practice Consistency
  - Pre-Job Briefing Content

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Current Initiatives

- Self-assessment
  - Working Level Involvement
  - Observation Based
  - Corrective Action Effectiveness Review
  - Utilization of Outside Participants

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Results

- Human Performance

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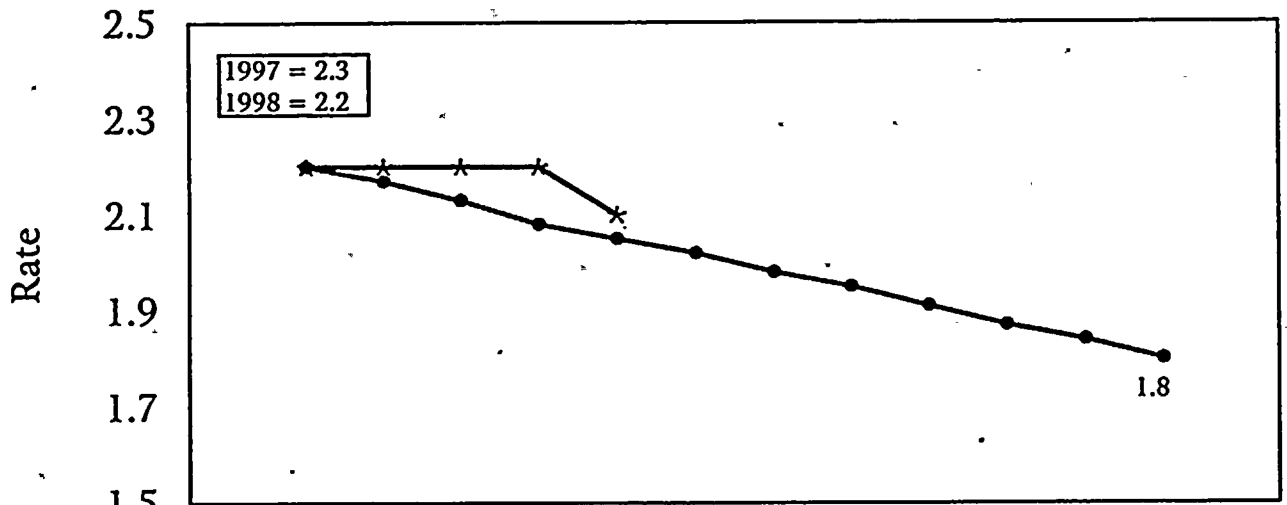
Site Personnel Error Rate

(F Cause Codes per 10,000 Person-Hours)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Actual	1.6	2.1	1.8	1.4	1.2							
12-Month Rolling Avg.	2.2	2.2	2.2	2.2	2.1							
YTD Goal	2.2	2.17	2.13	2.08	2.05	2.02	1.98	1.95	1.91	1.87	1.84	1.8

12-Month Rolling Avg. YTD Goal

1999

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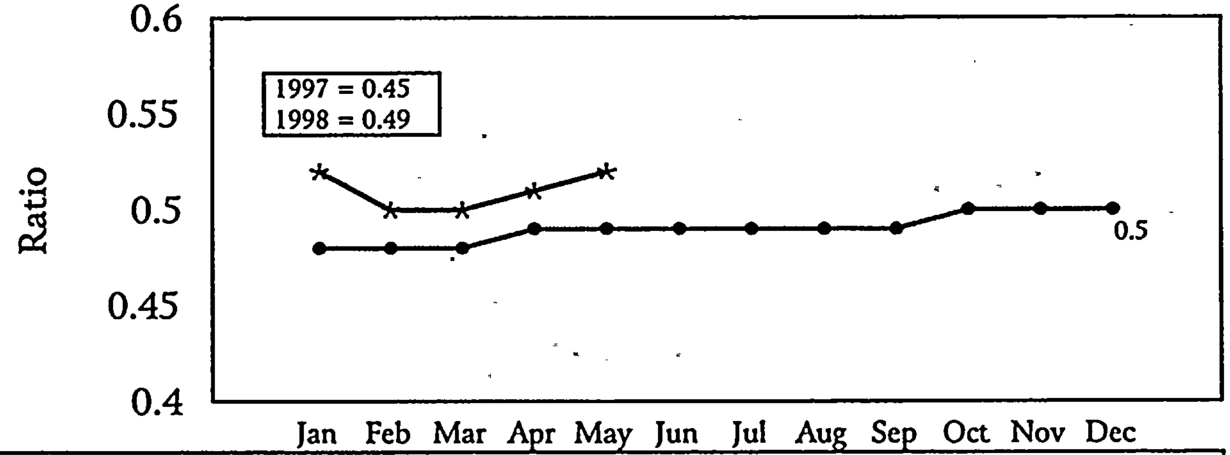
Site Self-Identified Personnel Error Ratio



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Actual	0.62	0.53	0.58	0.48	0.53							
12-Month Rolling Average	0.52	0.5	0.5	0.51	0.52							
YTD Goal	0.48	0.48	0.48	0.49	0.49	0.49	0.49	0.49	0.49	0.5	0.5	0.5

12-Month Rolling Average — YTD Goal

1999

Results

- Leadership Behavior
  - Reactor Building Drain Piping Success
  - RFO7 Preparation Progress
  - Outage Drywell Coordinator Success

Leadership Academy

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Theme

"Developing Leaders for Organizational Results"

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Leadership Academy

A forum to gain and practice the leadership behaviors needed to align participants with Nine Mile Point's vision of "highly valued people operating highly valued assets."

...John Mueller

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Leadership Academy Candidates

- Incumbent general supervisors
- First-line supervisors
- Others in leadership positions

Candidate Acceptance

- Based on preference for class makeup
  - Across groups
  - Level and experience

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Profile

- Three Week Program
- Experiential Learning Techniques
- Supervisory Skills
- Group Projects and Case Studies

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Profile

- Support Partner Relationships
- Branch Managers and Senior Managers
- Daily Journaling
- Weekly Branch Manager Meetings

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Core Program - Week 1

- Learning Environment
- Transition to Leader
- Responsibility/Accountability
- Safety Conscious Work Environment
- Professionalism
- EAP/Stress Management
- Paradigm Shifts
- Interpersonal Skills
- Trust
- Feedback
- Problem Solving/Decision Making
- Strategic Planning
- Myers-Briggs Type Indicator
- Situational Leadership
- Coaching
- Diversity
- Safety
- Human Performance
- Building a Partnership With Your Manager

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Core Program - Week 2

- Competition/Collaboration
- Planning
- Project Leadership
- Employee Concerns Program (Q1P)
- Presentation Skills
- Business Fundamentals
- Procurement
- Leading Organizational Change
- Team Development
- Managing Agreement
- Dealing With Conflict
- Delegation
- Training (SAT)
- Self-Assessment
- Behavioral Reinforcement
- Security
- Time Management
- Labor Relations
- Groupthink/Challenger

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Core Program - Week 3

- Quality Assurance
- Budget and Cost Control
- Harassment
- Delegation
- Employee Relations
- Corrective Action Program
- Station Culture
- Human Resource Development
- Meeting Management
- Observation Skills
- Ethics
- Motivating People to Care
- Shared Leadership
- Round Table
- Manager Meeting
- Graduation/Reception

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Continuing Learning Environment

- Quarterly Continuing Training Sessions
  - Maintain Momentum
  - Address Current Challenges
  - Assessment and Post-Training Evaluation
  - Communication Network

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Leadership Academy

- Graduates Achieve Results Through
  - Improved teamwork and communication
  - Higher morale
  - Increased accountability for actions
  - Increased alignment
  - Demonstrated behavioral change

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Preparing People for Leadership's Changing Roles

Past ...

Technical Experts and Messengers

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Preparing People for Leadership's Changing Roles

Today ...

Our Leaders Develop and Empower our People

Leadership Academy Graduate

- Terry Bockman - Chief Shift Operator, Nine Mile Point Unit 1 Operations Department
- Fire Protection Crew Chief - 1981
- Licensed Reactor Operator at Nine Mile Point Unit 1 - 1987
- Graduate of first Leadership Academy class in October 1998

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Operations - *The Lead Group*

- The lead group demonstrates operational excellence and direction for the site

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Cultural Change

- Our site culture needs to change
- Professional leadership qualities that can foster *positive change*
- *Positive change* can lead to a sense of ownership and pride that in turn will translate to a safer, kinder, more efficient organization.

Promotional Video

- When completed, this video will be made available for use in safety meetings, continued training and other gatherings as appropriate.
- Designed to encourage participation in and promotion of the philosophy of the *Leadership Academy*.

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Lou Holtz Leadership Model

- Do what's right
- Do it to the best of your ability
- Treat others the way you want to be treated

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Leadership Demands

- Leadership demands courage and initiative to do the right thing...

Safety Conscious Work Environment

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Safety Conscious Work Environment

- Initial Assessment
- Business Plan Initiative
- Follow-up Assessment

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Initial Assessment - Safety Conscious Work Environment

- Requested by Senior Vice President and Chief Nuclear Officer
- Independent personnel used
- Standard review that was comprehensive and thorough

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Initial Assessment - Highlights of Results

- Overall Healthy Environment for Employees to Raise Up Concerns
- Corrective Action Program
  - Consistent with the employee survey results
- Employee Concerns Program
  - Program purpose not well understood

Initial Assessment - Highlights of Actions Taken

- Employee Concerns Program
  - Revision to General Employee Training
  - Module for Leadership Academy
  - Numerous communications to site personnel
  - Employee Assessment

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Business Plan Initiative - Employee Concerns Program

- Results
  - Sufficient number of alternate paths to raise up concerns
  - Program visibility still required enhancement
  - Represented personnel need to fill a stronger role in the initiative

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Follow-up Assessment - Safety Conscious Work Environment

- Analysis of allegations resulted in a focused follow-up assessment
  - Utilized same firm and methodology
  - Completed the assessment 1st quarter 1999

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Follow-up Assessment - Results

- General
  - DER expectations better understood
- Work Group Specific
  - Work environment satisfactory
  - Inconsistent implementation of labor practices

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Overall Summary

- Overall results found a healthy environment for employees to raise concerns
- Corrective actions/improvement initiatives are ongoing
- Employee re-assessment of the general comfort with raising concerns

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Employee Assessment

- Initial Involvement
  - Employees comfortable raising technical issues
  - Most issues related to labor practices
- Current Assignment
  - Labor issues continue but are improving
  - Q1P visibility improved
  - Supervisory interpersonal skills improving
- Overall Conclusions

Corrective Action Program

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Corrective Action Program

- Program Strengths
- Improvement Opportunities
- Improvement Actions
- Results

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Corrective Action Program Strengths

- Program is effective for problem identification with an appropriately low threshold
- Robust oversight of program
- Ongoing initiatives are directed at improving program effectiveness
- No significant repeat events
- Performance indicators show a positive trend in program implementation

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Corrective Action Program Opportunities

- Improve consistency of DER disposition quality
- Improve the effectiveness of using industry Operating Experience
- Improve consistency of branch self-assessments
- Improve corrective action effectiveness review practices

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Corrective Action Program Improvement Actions

- New group established to drive consistent implementation of Corrective Action Program
  - Prioritize or classify new plant Deviation/Event Reports (DERs)
  - Centralize screening and processing of industry event information
  - Perform quality reviews of significant DERs

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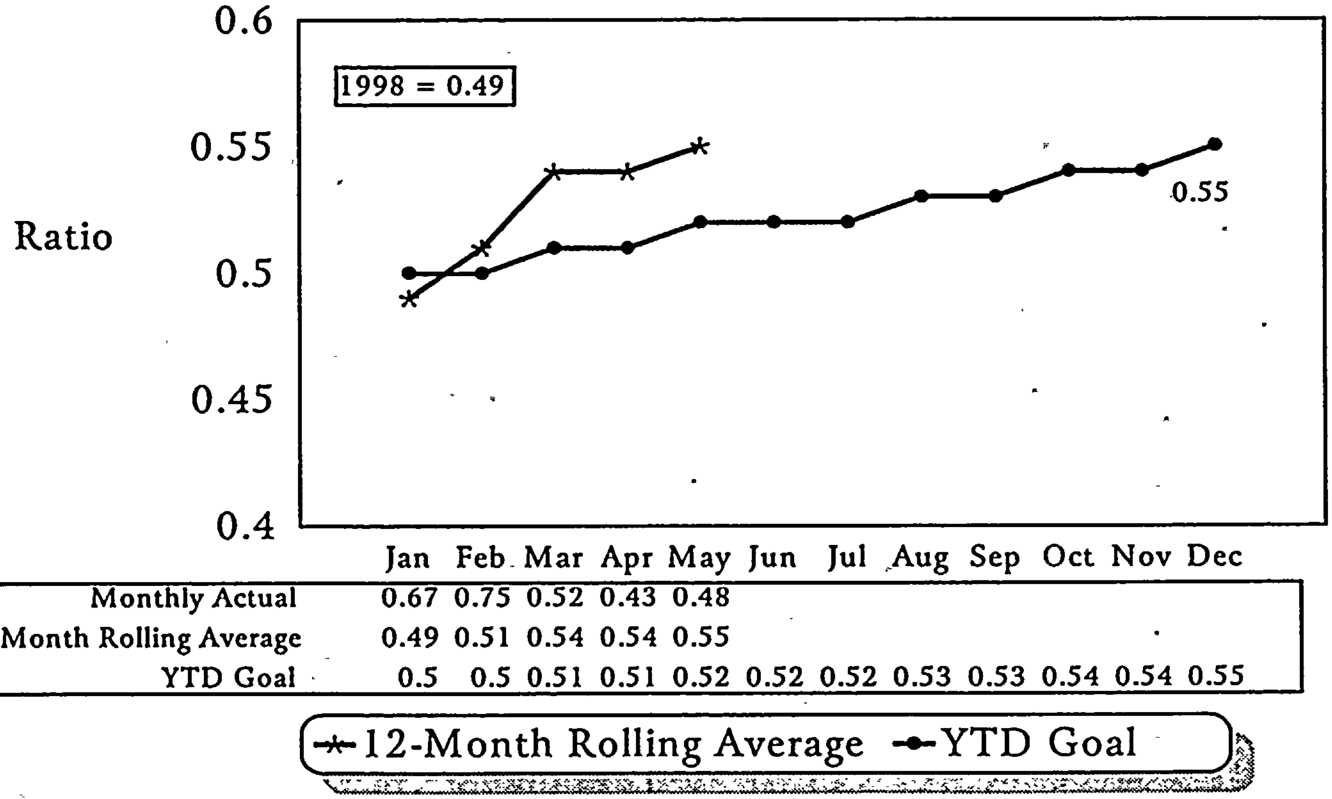
Corrective Action Program Improvement Actions

- Formalized "effectiveness review" expectations
- Focused manager attention on Category 1 and 2 DER dispositions
- Reducing average age of Category 1 and 2 DERs
- Enhancement of the DER database
- Improving access to Operating Experience information including "Just in Time" OE

Site Ratio of Self-Identified to External and Self-Revealing DERs



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Actual	0.67	0.75	0.52	0.43	0.48							
12-Month Rolling Average	0.49	0.51	0.54	0.54	0.55							
YTD Goal	0.5	0.5	0.51	0.51	0.52	0.52	0.52	0.53	0.53	0.54	0.54	0.55

1999

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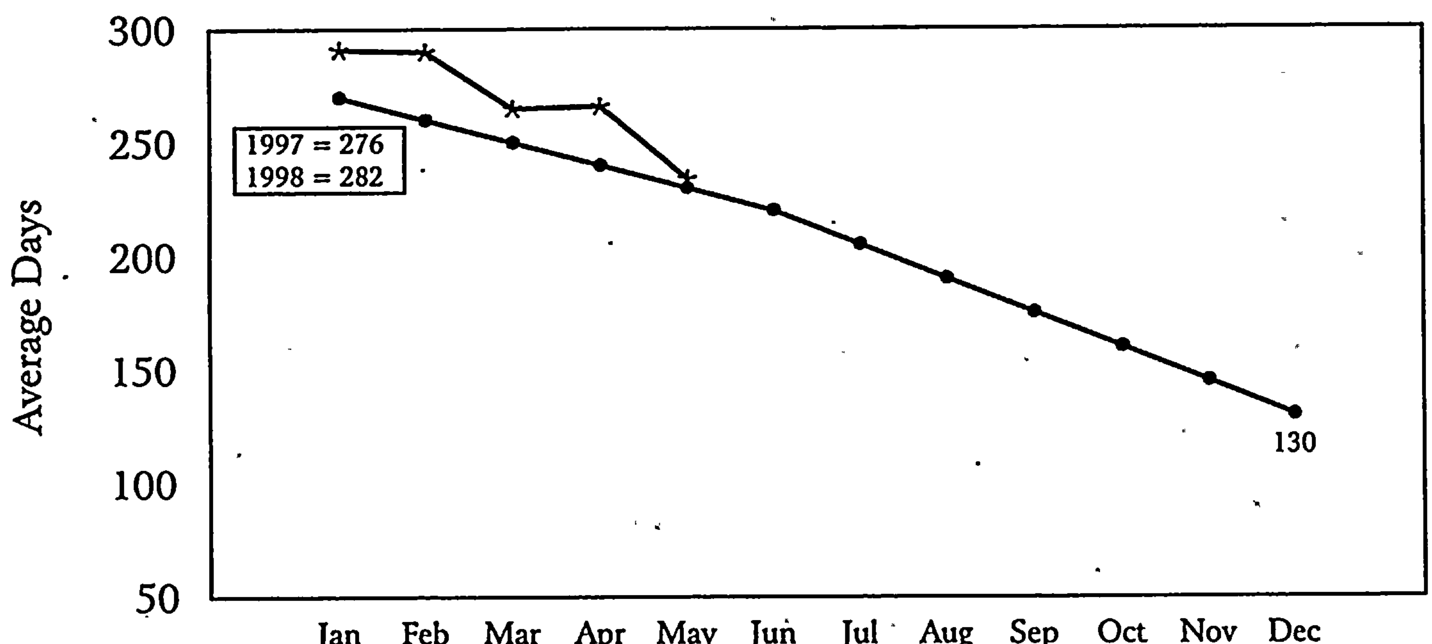
Site Average Age of Non-Outage Category 1 and 2 DERs



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
YTD Actual	291	290	265	266	234							
YTD Goal	270	260	250	240	230	220	205	190	175	160	145	130

—YTD Actual —YTD Goal

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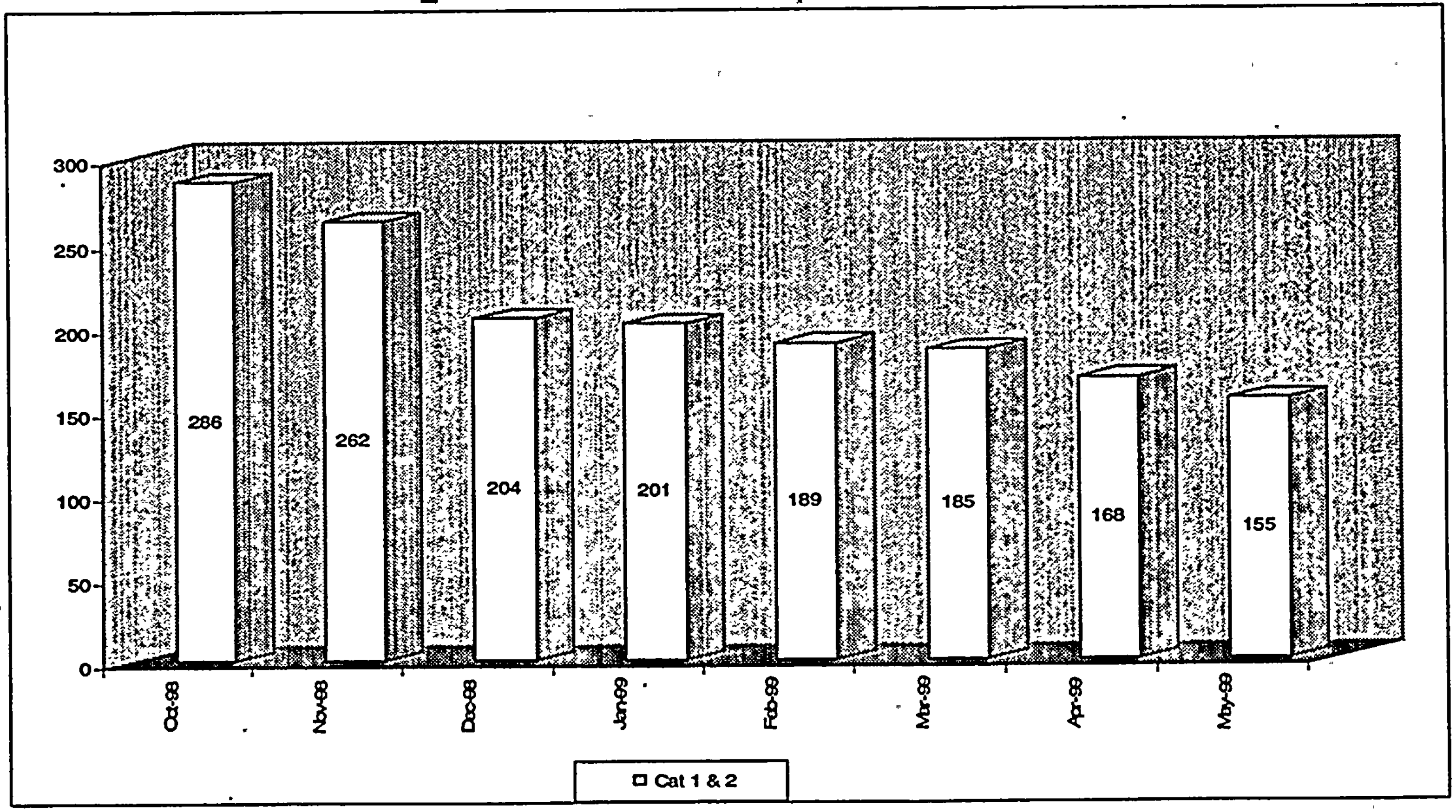
Category 1 and 2 DERs Open >1 Year



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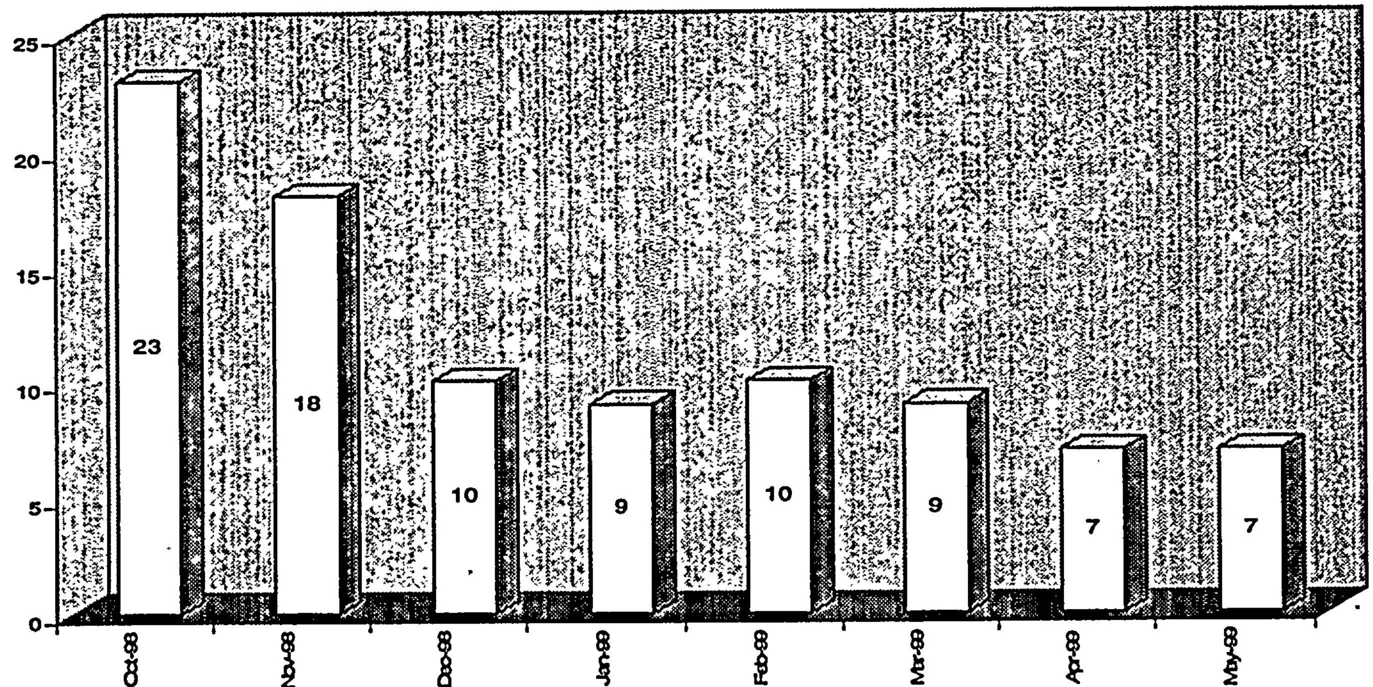
Category 1 and 2 DERs With Root Cause Open >1 Year



ENCLOSURE 3

LIST OF ATTENDEES

U.S. Nuclear Regulatory Commission

NAME	TITLE
H. Miller	Regional Administrator
A. Randolph Blough	Director, Division of Reactor Projects (DRP)
R. Crlenjak,	Deputy Division Director, DRP
W. Lanning	Director, Division of Reactor Safety
M. Evans	Branch Chief, Projects Branch 1, DRP
R. Fernandes	Resident Inspector, Nine Mile Point 1& 2
R. Conte	Branch Chief, DRS
W. Cook	Project Engineer, DRP
S. Chaudhary	Senior Reactor Engineer, DRS

Niagara Mohawk Power Corporation

NAME	TITLE
J. Mueller	Chief Nuclear Officer
J. Conway	V.P. Nuclear Generation
C. Terry	V.P. Nuclear Safety Assessment and Support
R. Hall	Director Human Resources
J. LeClair	General Supervisor Training Services
J. Ringwald	Supervisor Site Licensing
M. Briggs	Quality Assurance
T. Brockman	Unit 1 Operations

Pennsylvania Power & Light Company

NAME	TITLE
R. Kichune	Senior Licensing Engineer