U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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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
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TABLE OF CONTENTS

Table of Contents (cont'd)

Table of Contents (cont'd)

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
50-220/97-03 & 50-410/97-03
April 6 - May 17, 1997

This integrated NRC inspection report includes reviews of licensee activities in the functional areas of operations, engineering, maintenance, and plant support. The report covers a six week period of inspections and reviews by the resident staff, and regional specialists in the areas of radiation protection and security.

PLANT OPERATIONS

The Unit 1 core reload was well controlled; the pre-evolution briefing clearly communicated management expectations. Coordination between the control room and refuel operators was good, with clear and formal communication between the control room operators and personnel on the refuel bridge. However, during preparation for the reload, poor supervisory oversight and personnel inattention-to-detail resulted in the improper withdrawal of double blade guides in the area of fully inserted control rods. In addition, after the refueling, an inadequate procedure for lowering the reactor cavity water level allowed operators to overflow the reactor building equipment drain tank sump, spilling about 7,000 gallons of water to the surrounding area. Also, although the station shift supervisor (SSS) recognized that certain prerequisites were not satisfied, he continued with the evolution without processing a procedure change. **(VIO)**

Niagara Mohawk Power Corporation (NMPC) performed a detailed review of the NRC's Safety Evaluation Report regarding the Unit 1 core shroud cracking and tie rod modification. The management review was thorough and all managers exhibited a good questioning attitude.

The movement of a heavy load on the refueling floor outside the designated safe load path was a result of inadequate pre-planning and a lack of detailed safe load path procedural guidance. **(NCV)**

During the Unit 1 reactor start up, observations by quality assurance (QA) and training personnel were used to provide the control room crew with a critical post-shift critique of overall shift performance. The inspectors considered this very beneficial. Control room communications were formal and usually used three-part communications. Operator response to control room annunciators was appropriate, although alarm response procedures were not always used. Control room access was very good, only essential personnel were allowed entry into the at-the-controls area. Monitoring of reactor plant parameters was good.

The Unit 1 SSS's response to the rapid cooldown during a planned scram demonstrated good command and control. In addition, the use of a reactor operator dedicated to controlling reactor water level was appropriate. However, control room operators failed to consistently use three-part-communications, as expected by NMPC management. The

planned evaluation of lessons learned from the rapid cooldown, for potential enhancements to the operations procedures and training was prudent.

The NMPC identification of the inadequate residual heat removal minimum flow valve position indication (VPI) at the Unit 2 remote shutdown panel (RSP) was considered good. Also, the recognition that the deficiency adversely impacted the remote shutdown procedure indicated a good safety perspective. However, the failure to have adequate contingency for a loss of the VPI was contrary to the Updated Final Safety Analysis Report (UFSAR) requirement to have operating instructions in the event of a control room fire, and was a violation of 10CFR50.59. However, pending the resolution of similar issues identified in inspection report 50-220 and 50-410/97-05 which are being considered by NRC management for possible escalated enforcement, this item remains unresolved. **(URI)** Also, the procedure change to address the deficiency was not reviewed with respect to the fire protection program, as evidenced by the failure of NMPC to identify the inadequate emergency lighting. **(VIO)** Additionally, documented engineering justification for the procedure change was poor, in that additional information from the engineer was required to justify the basis for the change.

Equipment material condition and compartment housekeeping during the Unit 1 refueling outage were good and consistent with the ongoing level of maintenance activity. Prior to startup, an appropriate level of management attention to housekeeping was evidenced by adequate plant cleanliness, even areas in which significant debris accumulated during the outage.

The performance of a Unit 1 operating crew during a simulator evaluation was acceptable, although several weaknesses were identified by the NMPC evaluators and the NRC inspectors. These indicate a need for continuing emphasis on communication techniques, attention to detail, command and control by shift supervision, and shift technical advisor knowledge.

The absence of both the low level and low pressure alarms at Unit 1 when the #12 nitrogen (N_2) tank was empty is a violation of 10CFR50.59. **(NCV)** Also, in 1995, the control room operators failed to recognize that one alarm had cleared erroneously and another failed to annunciate. The inspectors considered this was a significant weakness at that time with respect to operator performance.

The licensee's corrective actions for the initial (September 1995) loss of full-in indication for a control rod following a scram, although not aggressive, were acceptable. However, the corrective actions following the second occurrence were weak. Furthermore, there were three occasions during which additional corrective actions could have been performed to prevent recurrence; but the work control process missed an opportunity to trouble shoot the problem during the last plant shutdown, when the under vessel area was accessible. The current corrective actions appear to be sound.

MAINTENANCE

The hydrostatic pressure test of the Unit 1 reactor vessel and pressure boundary piping and components was conducted cautiously and with good management oversight. Procedural limits and safety considerations were highlighted during the pre-evolution briefing by senior management.

ENGINEERING

A review of the Unit 2 10CFR50, Appendix J Leak Rate Program, showed that procedures appropriately reflect the established acceptance criteria, and that appropriate means are in place to ensure the Technical Specification limit on total leakage is tracked. The reassignment of the responsibility to track total leakage to the Technical Support group allowed for increased resources to monitor the Appendix J Program, and was considered appropriate.

Although NMPC ultimately determined that the some Unit 2 valves were not containment isolation valves and thus were not required to be included on the Controlled List, a lack of communication between engineering and operations departments in 1995 resulted in a failure to appropriately include the valves in the surveillance test procedure. **(NCV)**

PLANT SUPPORT

Chemistry

Independent calculations verified that Unit 2 reactor water conductivity continues to meet the requirements for a Category "A" shroud, in accordance with NUREG-1544.

Radiological Protection

Overall, the radiological protection (RP) program was well implemented. The RP controls during the Unit 1 refueling outage, and the calibration programs for area radiation monitors at both units were well implemented. Proper RP controls were applied during operation of the Thermex system. RP-related QA activities were effective in assuring program performance.

Security

NMPC was conducting security and safeguards activities in a manner that protected public health and safety. The program met the regulatory requirements and commitments, with the exception of protected area access control of vehicles. In particular, designated vehicles were not being controlled as required in the Security Plan and procedures. **(VIO)**

Alarm station operators were knowledgeable about their duties. Security training was conducted in accordance with the approved plan and appeared effective. Management support for the security program was effective, as evident by the replacement of several monitors in the alarm stations, procurement of new response weapons, and security manning levels. Management controls for identifying, resolving, and preventing programmatic problems appeared to be effective. The 1996 security audit was comprehensive in scope and depth, and the audit program was being properly administered.

Fire Protection

The fire protection staff performance of a Cardox system surveillance test was good. The staff was knowledgeable regarding the surveillance test, and communications between the technicians and the control room were very good.

NMPC's actions for numerous missing and/or failed Appendix R emergency lights were acceptable. However, weaknesses were identified with respect to operability determinations for equipment not addressed in the Technical Specifications; and the length of time required to recognize that the condition was reportable to the NRC. **(NCV)**

DETAILS

Nine Mile Point Units 1 and 2
50-220/97-03 & 50-410/97-03
April 6 - May 17, 1997

SUMMARY OF ACTIVITIES

Niagara Mohawk Power Corporation (NMPC) Activities

Unit 1

Nine Mile Point Unit 1 (Unit 1) began the inspection period shutdown for the fourteenth refueling outage (RFO14). Startup of Unit 1 commenced on May 9, 1997; on May 10, 1997, the unit was shutdown due to excessive turbine generator vibration. Unit 1 was restarted on May 12, 1997. On May 14, 1997, the unit was again shutdown to repair a pin-hole leak in a weld at the inlet to the reactor water cleanup regenerative heat exchanger. Unit 1 remained in cold shutdown through the end of the inspection period.

Unit 2

Nine Mile Point Unit 2 (Unit 2) essentially maintained full power during the inspection period.

Nuclear Regulatory Commission (NRC) Staff Activities

Inspection Activities

The NRC conducted inspection activities during normal, backshift, and deep backshift hours. In addition to the inspection activities completed by the resident inspectors, regional specialists conducted reviews in the areas of radiological controls and security. The results are contained in the applicable sections of this inspection report.

Updated Final Safety Analysis Report Reviews

A discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for additional verification that licensees were complying with UFSAR commitments. While performing the inspections discussed in this report, the inspectors reviewed the portions of the UFSAR related to the areas inspected to verify that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. Four exceptions were noted; see Sections 02.1, O8.1, E8.1 and F2.2 for details. In addition, during a review of the Nine Mile Point security plan, which includes the security program requirements not specified in the UFSAR, another discrepancy was identified and is described in Section S1.2.

I. OPERATIONS

O1 Conduct of Operations (60710, 71707, 90712, 92700) [1]

O1.1 General Comments

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

O1.2 Improper Movement of Unit 1 Double Blade Guides

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the withdrawal of double blade guides (DBGs) in the area of fully inserted control rods during Unit 1 preparations for refueling. Fully inserted control rods are normally supported laterally by the surrounding fuel bundles; during fuel offload conditions, a DBG is inserted to provide the lateral support. The inspectors discussed the issue with reactor engineering supervision and reviewed the associated Deviation/Event Report (DER).

b. Observations and Findings

On April 12, 1997, with the core fully offloaded, reactor engineering supervision authorized rearrangement of control rod DBGs in preparation for core reload. Using guidance provided in NMPC Procedure N1-FHP-25, "General Description of Fuel Moves," a Fuel Movement Instructions sheet was developed to sequence the DBG moves.

After withdrawing the DBG from position 22-03, refuel bridge personnel determined that control rod 22-03 was fully inserted. The senior reactor operator (SRO) on the bridge directed the DBG to be lowered back into the cell and the control room was notified. The control room reviewed previous DBG moves and determined that the DBG removed from position 50-31 was also associated with a fully inserted control rod. The Station Shift Supervisor (SSS) directed reinstallation of the DBG at position 50-31, and halted all work on the refuel bridge.

The licensee discussed the operability of the two affected control rods with General Electric (GE) Company personnel. The GE personnel noted that the control rod blades appeared to remain straight after DBG removal, and the DBGs were easily reinstalled. There appeared to be no damage to the control rods or control rod

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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.

drives (CRD). To confirm rod operability, the CRDs were to be stroke-time tested, coupling integrity checked, and scram-time tested. These checks were subsequently performed satisfactorily.

Procedure N1-FHP-25 describes fuel movements, but does not specifically address control and movement of DBGs. The licensee characterized this error as a "near-miss," in that the potential existed for damaging in-core components, had the control rod become uncoupled and fallen. Although this incident did not violate NRC regulations, the inspectors noted that inattention to detail and poor supervisory oversight resulted in numerous opportunities to avert the near-miss. NMPC identified the following as contributing factors to the occurrence:

- The reactor engineering supervisor authorized the DBG movement, but did not consider that some of the DBGs may have had fully-inserted control rods.

- The preparer, and the approver, of the Fuel Movement Instructions sheet both failed to verify that no fully-inserted rods existed.

- Although the SRO and reactor analyst technician on the refuel bridge attempted to visually verify that the DBGs being moved were not associated with a fully-inserted control rods, insufficient lighting resulted in poor visibility and an incorrect determination that the control rods were not fully inserted.

- The control room staff was aware of the DBGs to be repositioned; however, no one independently verified that the associated control rods were not fully inserted.

- The SSS and Chief Shift Operator did not maintain adequate oversight of the evolution, in that they relied solely upon the reactor engineers' knowledge of in-core status for authorizing the DBG moves.

As corrective actions, NMPC modified Procedure N1-FHP-25 to require verification of control rod positions and to ensure that rods are fully withdrawn prior to moving DBGs. Also, operators on the refuel floor must verify adequate lighting when performing visual checks to ensure the rod is properly withdrawn. The Operations Manager discussed with control room staff the need for personal accountability and that their decisions are not to be influenced by the technical competency of others.

c. <u>Conclusions</u>

At Unit 1, poor supervisory oversight by the reactor engineering supervisor and the SRO on the bridge, and personnel inattention-to-detail by all involved, resulted in the improper withdrawal of DBGs surrounding fully inserted control rods.

O1.3 Conduct of Unit 1 Core Reload Operations

a. Inspection Scope

Using the guidance provided in NRC Inspection Procedure 60710, the inspectors observed licensee and contractor (GE) conduct of operations during Unit 1 core reload. The inspectors observed the evolution from the control room, the refuel floor, and in the reactor building during both normal and backshift hours. The inspectors also reviewed applicable procedures and Technical Specifications (TS) to verify licensee compliance.

b. Observations and Findings

On April 17, 1997, the inspectors attended a Management Expectations Briefing conducted by the Unit 1 Operations Manager and reactor engineering department supervisor. The briefing was conducted in accordance with licensee Procedure GAP-SAT-03, "Control of Special Evolutions," Revision 02. The briefing included the following topics: purpose and methodology of core reload; roles and responsibilities; precautions and prerequisites; and communications. Additionally, the Operations Manager emphasized previous lessons learned and provided clear management expectations.

On April 18, 1997, GE and Unit 1 operations personnel commenced reloading the core. The inspectors reviewed the following procedures:

- N1-FHP-25, "General Description of Fuel Moves," Revision 13
- N1-FHP-27B, "Whole Core Reload," Revision 01
- N1-ODP-NFM-101, "Refueling Operations," Revision 01

The inspectors observed that the control room operators adhered to approved procedures during fuel movement operations. Communications from the control room were very clear and three-part communication was utilized. The overall command and control function from the control room was very good, in that control room operators effectively managed refuel floor operations. The coordination between the control room and refuel floor operators was good, and allowed control rod manipulations and fuel bundle movements to be performed concurrently without incident.

The inspectors observed operations staff and GE personnel perform fuel movement from the refuel bridge. The evolutions were controlled and in accordance with procedures. All applicable TS requirements were met. NMPC and GE personnel exhibited excellent formal three-part communication. The inspectors noted operations management and supervision oversight, as well as Quality Assurance (QA) staff periodically on the refuel bridge.

c. Conclusions

Core reload activities, in general, were well controlled and performed. The special evolution briefing prior to Unit 1 core reload clearly provided management expectations. Control room operators and contracted personnel on the refuel bridge exhibited clear and formal three-part communications. Coordination between the control room and refuel floor operators was good.

O1.4 Overflow of Unit 1 Reactor Building Sump During Reactor Cavity Draining

a. Inspection Scope

During reinstallation of the Unit 1 reactor vessel internals, personnel inadvertently lowered the water level in the reactor cavity and internals storage pit, causing the reactor building equipment drain tank (RBEDT) to overflow. The inspectors reviewed the DER and discussed the event with the shift personnel and the plant management.

b. Observations and Findings

On April 23, 1997, as part of the process to return the steam separator to the reactor vessel, preparations were being made to lower the water level in the Unit 1 reactor cavity and internals storage pit. The evolution was to be conducted in accordance with NMPC Operating Procedure N1-OP-6, "Fuel Pool Filtering and Cooling System," Revision 14, Section H.3.0, "Lowering Head Cavity and Internals Storage Pit Water Level Using the Spent Fuel Pool System." By procedure, the reactor cavity was to be drained to the turbine condenser, with the RBEDT isolated from the reactor cavity.

Approximately one-half hour after starting the lineup, an alarm was received in the control room for a high level in the northeast-corner reactor building floor drain sump. High sump level is one of the entry conditions for the emergency operating procedures (EOP); subsequently, the SSS entered the EOP-5, "Secondary Containment Control."

The root cause analysis of the event performed as part of DER 1-97-1274 identified two issues: (1) the procedure that allowed the sump to overflow was technically inadequate; and (2) the shift personnel recognized that they were not following the procedure, but failed to change it prior to continuing. With respect to the first issue, Procedure N1-OP-6 did not specify a maximum storage pit level prior to starting the evolution. Before starting the valve lineup, the storage pit water level was about two feet higher than the spent fuel pool (SFP) surge tanks. Thus, when valve 54-17 (blocking valve for the SFP to the suction of the circulating pumps) was opened, there was a path for the surge tanks and storage pit to equalize levels. The surge tanks overflowed to the RBEDT sump, as designed; the sump overflowed because the capacity of the sump pump was exceeded. Approximately 7,000 gallons overflowed the sump, and was contained in the immediate area of the RBEDT; causing the floor in the northeast corner room of the reactor building to

become contaminated. The DER identified that the procedure was inadequate with respect to a maximum level in the storage pit, in that it did not include a precaution or note alerting the operators to the potential for siphoning the storage pit into the surge tanks and, further, to overflow the RBEDT sump.

With respect to the second issue, Procedure N1-OP-6, Section 3.1.1, required the SFP gates be removed, and Section 3.1.7 required a condensate pump be in service prior to lowering cavity and storage pit water level. The SSS recognized that two prerequisites were not met and requested the shift technical advisor (STA) initiate a procedure change evaluation (PCE). However, prior to completing the PCE, the SSS and STA determined that there were no technical reasons to perform the prerequisites and determined that the procedure change was not required. The post-event review by NMPC management determined that the technical basis for the SSS decision was justified. Nonetheless, failure to change the procedure prior to proceeding was a violation of NMPC Procedure NIP-PRO-01, "Use of Procedures," Revision 3, and Technical Specification (TS) 6.8.1 regarding procedure adherence. **(VIO 50-410/97-03-01)** A detailed root cause was completed, as documented in DER 1-97-1274. In addition, corrective actions have been implemented or planned to address the immediate concern and to prevent recurrence; these include: (1) counseling of involved shift personnel with respect to the requirement to correct procedure errors prior to performance, (2) meetings with all operations department personnel regarding procedure adherence, and (3) a planned self-assessment of shift performance to determine the effectiveness of the preventive actions. The corrective actions appear appropriate; therefore, no response will be required for this violation and this violation is closed.

The inspectors independently determined the sequence of events, discussed the details with the SSS and station management, and reviewed the associated operating procedure and system lineup. Also, the inspectors determined that the DER satisfactorily described the event, and identified adequate root cause analysis and corrective actions.

c. Conclusion

Due to an inadequate procedure for lowering Unit 1 reactor cavity water level after refueling, the RBEDT sump overflowed and spilled about 7,000 gallons of water to the surrounding area. In addition, the SSS recognized that certain prerequisites were not satisfied, but continued with the evolution without processing a procedure change. (VIO) These are examples of a lack of attention to the task at hand and a weak procedure review process.

O1.5 NMPC Incorporation of Requirements Associated with the NRC Approval of Core Shroud Cracking Evaluation

a. Inspection Scope

During the 1997 Unit 1 refueling outage, NMPC identified cracking of the core shroud and failure of the shroud tie-rod lower wedge retainer clips. In a letter to the

NRC, NMPC submitted the details of their findings, including root cause and proposed corrective actions, and requested approval of the repairs. The inspectors monitored NMPC's review of the NRC response, and the incorporation of the associated contingencies.

b. Observations and Findings

In January 1997, during the Unit 1 refueling outage, NMPC identified deficiencies related to cracking of the core shroud vertical welds and failure of the shroud tie-rod lower wedge retainer clips. NMPC submitted the details of their findings, root cause analysis, and proposed corrective actions to the NRC for review (dated April 8, 1997). Since the modification of the lower wedge retainer clips was not described in the American Society of Mechanical Engineers (ASME) Code, Section XI, NMPC needed NRC approval of the repairs, pursuant to Title 10 of the Code of Federal Regulations (10 CFR) 50.55(a)(3)(i), prior to restart of the reactor.

On May 8, 1997, the NRC responded to NMPC and stated that the modification for the lower wedge retainer clip design was acceptable. In addition, the NRC determined that the vertical welds were acceptable for 10,600 hours of "hot operation" (>200°F). However, the approval was contingent upon (1) maintaining reactor coolant chemistry within the guidelines of the Electric Power Research Institute technical report (EPRI TR-103515), "BWR [Boiling Water Reactor] Water Chemistry Guidelines" - 1996 Revision, and (2) submitting, within 60 days, an application for license amendment to address the difference between the current Unit 1 TS conductivity limits and the conductivity assumptions used for crack growth rate analysis. The BWR water chemistry guidelines and associated Action Levels, as detailed in EPRI TR-103515-R1, Section 4, are listed in Attachment 2 of this report.

The inspectors observed the meeting where NMPC management reviewed the NRC response. The inspectors verified that the EPRI chemistry guidelines were adequately incorporated into the appropriate Unit 1 Chemistry Procedure, N1-CSP-D100, "Reactor Water Chemistry." Also, Operations Department Standing Order #7, "Chemistry Control Guide," was issued to the Unit 1 control room operators to emphasize the requirements contained in the chemistry procedure. For power operation ≥10%, the Standing Order requires that chemistry supervision be notified if conductivity is ≥0.15 micro Seimens per centimeter (μS/cm) or chloride is ≥1.0 parts per billion (ppb). If conductivity exceeds Action Level 1 (0.3 μS/cm) at all, the Plant Manager is to be notified; if greater than Action Level 1 for 24 hours, then a normal orderly shutdown is to be initiated.

c. Conclusion

Overall, NMPC performed a detailed review of the NRC Safety Evaluation Report regarding the core shroud cracking and the tie-rod modification, and incorporated the contingencies into the applicable procedures. The management review was thorough and all managers exhibited a questioning attitude, often challenging each other's comments to ensure no options had been overlooked.

O1.6 Movement of Heavy Loads During Unit 1 Refueling Outage

a. Inspection Scope

During the Unit 1 refueling outage, the inspectors monitored heavy load movements within the reactor vessel cavity, the SFP, and the internals storage pit. The inspectors discussed with reactor engineering and design engineering staff the precautions taken to ensure that heavy loads did not result in damage to safety-related equipment, and the potential consequences resulting from "silver-dollar" failure.

b. Observations and Findings

Maintenance Procedure N1-MMP-GEN-914, "Lifting of Miscellaneous Heavy Loads," governs heavy load lifts and defines a "heavy load" as any load exceeding 1,000 pounds. Rigging practices, defined load-paths, and specific load limits resulted in safety factors which corresponded to a very low probability of dropping a load that could potentially damage safety-related equipment, and specifically fuel bundles stored in the SFP. Load lifts greater than 1000 pounds were performed in accordance with NUREG 0612, "Control of Heavy Loads at Nuclear Power Plants."

During removal of the old core shroud 270° tie-rod (1220 pounds), and reinstallation of the new one, the tie-rods were moved over the reactor cavity-to-drywell silver-dollars. The silver-dollars are aluminum cover plates over the upper drywell ventilation standpipe openings, that prevent water from entering the drywell during reactor cavity flood-up conditions. Penetration of a silver-dollar would result in drywell flooding and could significantly lower SFP water level.

Silver-dollar installation is performed in accordance with NMPC Procedure N1-MMP-GEN-904, "Reactor Vessel Moisture Separator and Spent Fuel Pool Canal Gate Removal and Installation." Reactor engineering staff stated that the silver-dollars were cleaned and visually inspected prior to installation, but no formal documentation was required. The silver-dollars were then bolted onto the ventilation standpipes using new gaskets each refueling cycle. The silver-dollars were subsequently leak-tested.

The inspectors questioned whether design engineering had performed a load drop analysis relative to silver-dollar failures from drops of "light load" lifts (i.e., loads less than 1000 pounds). Design engineering stated that a load drop analysis was not performed, nor required, for loads less than 1000 pounds. Maintaining an adequate safety factor for smaller loads was common practice. However, based on the inspectors' questions, and an event at another facility where a moisture separator tie-down bolt was dropped and punctured a SFP liner, design engineering was reviewing the need to analyze the consequences of a heavy load dropped onto a silver-dollar. The inspectors considered this action appropriate.

During the movement of the 270° tie-rods, the licensee deviated from the load path specified in Procedure NM-SHD-002, "Nine Mile Point 1 Shroud Stabilizer

Modification Installation Procedure." Specifically, the new tie-rod was transported approximately 10-20 feet farther West within the internal storage pit, taking the tie-rod over the moisture separator. The tie-rod was subsequently moved North to its designated storage area on the refuel floor. QA initiated a DER to ensure the cause and corrective actions of the occurrence were documented. The inspectors considered this safe load path deviation to have minimal safety consequence; but, it was a violation of Procedure NM-SHD-002, resulting from inadequate pre-planning and the lack of detailed safe load path procedural guidance. This minor violation is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/97-03-02)**

The inspectors also noted that, during movement of the old tie-rod from the internals storage pit to the SFP, the original safe load path was to circumvent the reactor cavity. However, due to obstructions which would have resulted in significant raising of the tie-rod, the safe load path was changed to transfer the tie-rod over the reactor cavity. In this instance, the procedure was properly revised to reflect the safe load path change prior to tie-rod movement. The inspectors considered the safe load path change appropriate and was adequately evaluated by the licensee.

NMPC Procedure N1-OP-34, "Refueling Procedure," Revision 14, allows for the continued removal of the fuel transfer canal gates. The procedure discusses operational contingencies if no refueling activities are planned within 72 hours which require movement of components through the fuel transfer canal. Although N1-OP-34 allows for continued gate removal, the inspectors discussed with the Unit 1 Plant Manager the consequences of a silver-dollar failure during that condition. The inspectors were concerned that if a silver-dollar was damaged without the gates installed, SFP water level would lower appreciably. The Plant Manager noted that NMPC Procedure N1-SOP-20, "Loss of SFP/Rx Cavity Level/Decay Heat Removal," Revision 03, addressed operator response to a lowering SFP water level. Additionally, for lowering SFP water level without makeup, the Unit 1 UFSAR, Chapter X, Section 3.0, states that "if no actions were taken, the fuel would still be covered by approximately 1 foot of water after the pool had drained down to the lowest penetration" and that this coverage would "... permit unrestricted access to the operating floor." The inspectors consider the ability for operators to reestablish SFP water level, and the design of the SFP to maintain the fuel covered during an inadvertent draining, as adequate justification for not installing the SFP gates during extended periods without fuel movement.

c. <u>Conclusions</u>

The movement of the new 270° tie-rod outside the designated safe load path was a violation resulting from inadequate pre-planning and lack of detailed safe load path procedural guidance. (NCV) Operator ability to reestablish SFP water level and the design of the SFP to maintain the fuel covered during an inadvertent draining were adequate justification for not installing the SFP gates during extended periods without fuel movement.

O1.7 Unit 1 Reactor Startup Following the Fourteenth Refueling Outage (RFO14)

a. Inspection Scope

The inspectors monitored the Unit 1 reactor and balance-of-plant startup following RFO 14. The inspectors observed control room activities during both normal and backshift hours, and discussed their observations with control room supervision and operations management.

b. Observations and Findings

On May 9, 1997, Unit 1 operations staff commenced a normal reactor startup following RFO14. The mode switch was placed in STARTUP at 2:23 a.m., and the reactor was declared critical at 4:23 a.m. The inspectors verified that all prerequisites required by NMPC Procedure N1-PM-V16, "Reactor Startup and Shutdown Prerequisite Verifications," Revision 01, were satisfactorily completed.

The inspectors noted that the Operations Manager, and QA and Training staff were present during much of the startup to monitor the performance of the control room staff. The QA and Training organizations provided immediate feedback to the control room staff and operations management regarding identified concerns. The inspectors considered this effort very beneficial toward providing the control room crew with an immediate post-shift critique of overall performance regarding strengths and weaknesses.

Generally, communications were formal and three-part communications were usually utilized. The inspectors noted that three-part communication was used consistently between the reactor analyst and operator manipulating control rods. However, the communications between other operators, at times, lacked the three-part format. Operator response to control room annunciators was appropriate, although alarm response procedures were not always used. Discussions with the Operations Manager and Plant Manager noted that this did not meet their expectations. Control room access was very good, in that only essential personnel were allowed access to the at-the-controls area.

Monitoring of reactor plant parameters by control room personnel was good. The licensee had an operator dedicated to monitoring and maintaining reactor vessel water level during the startup. Reactor vessel level was adequately maintained during the startup.

c. Conclusions

During the Unit 1 reactor start up, the QA and Training effort of providing the control room crew with an immediate post shift critique of overall shift performance regarding strengths and weaknesses was very beneficial. Control room staff communications were formal and three-part communications were usually utilized. Operator response to control room annunciators was appropriate, although alarm response procedures were not always used. Control room access was very good,

in that only essential personnel were allowed access to the at-the-controls area. Monitoring of reactor plant parameters was good.

O1.8 Unit 1 High Turbine Vibrations and Manual Reactor Scram

a. Inspection Scope

The inspectors observed control room activities during the manual scram of the Unit 1 reactor following the identification of higher than normal turbine vibrations while performing a reactor startup from RFO14. The inspectors also reviewed applicable procedures and the licensee's planned-scram evaluation.

b. Observations and Findings

On May 10, 1997, during the initial reactor startup following RFO14, higher than normal turbine generator vibrations were experienced. After NMPC review by management and consultation with GE, the Unit 1 operators tripped the turbine and inserted a manual scram to shutdown the reactor. The scram was initiated with the reactor at 18% power. Control room operators completed the scram actions in accordance with approved procedures. However, the inspectors observed that control room operators did not consistently use three-part communications, as expected by the NMPC management.

During previous Unit 1 scrams, deficiencies in controlling reactor vessel water level were identified (see NRC Inspection Report (IR) 50-220/96-13). Therefore, prior to the scram, a reactor operator was stationed with the sole responsibility of controlling water level within a specified band; the operator took manual control and maintained the water level within the assigned band.

Since there was no appreciable decay heat in the core, due to the extended shutdown period, reactor pressure dropped off rapidly following the scram. The SSS demonstrated good command and control of the situation, directing the operators to isolate steam loads and shut the main steam isolation valves to maintain the cooldown rate within the acceptable limits. Following the scram, the Operations Manager initiated a DER to evaluate potential enhancements to the operations procedures and training, for handling this type of rapid pressure drop situation.

c. Conclusion

The operators' response to the high turbine vibration and manual scram was appropriate. The Unit 1 SSS's response to the rapid cooldown during the turbine trip and manual scram on May 10, 1997, was considered an example of good command and control. In addition, the use of a reactor operator dedicated to controlling reactor water level was appropriate. However, control room operators failed to consistently use three-part-communications, as expected by their management. The planned evaluation of lessons learned from the rapid cooldown

for potential enhancements to the operations procedures and training indicated a good questioning attitude.

O2 Operational Status of Facilities and Equipment (71707)

O2.1 Inadequate Procedure for the Remote Shutdown Procedure of Unit 2

a. Inspection Scope

In May 1997, NMPC notified the NRC that the Unit 2 procedure for remote shutdown did not provide adequate contingency to ensure residual heat removal (RHR) pump minimum flow protection in the event of a control room fire. The inspectors evaluated the details associated with the issue and the licensee's actions taken to correct the deficiency. During the evaluation, the inspectors reviewed the associated DER, operations and administrative procedures, procedure change documentation, and applicable portions of the Unit 2 UFSAR. Additionally, the inspectors had discussions regarding the issue with the Unit 2 Plant Manager and members of the design engineering staff.

b. Observations and Findings

On May 8, 1997, during a review of the Unit 2 remote shutdown panel (RSP) design, the Independent Safety Engineering Group (ISEG) identified that the RSP valve position indication (VPI) for the "A" and "B" RHR pump minimum flow valves was not electrically isolated from the main control room. Although the plant design, as described in the UFSAR, did not require these circuits at the RSP to be isolated from the main control room in the event of a main control room fire, the potential existed for a fire-induced short-circuit to cause the circuits to fail. This failure would result in a loss of RHR minimum flow VPI at the RSP. The licensee documented this issue in DER 2-97-1434 and initially determined the problem not to impact the operability of the RSP; however, an engineering supporting analysis was being performed to support the RSP operability. In addition, the initial determination by the licensee was that the issue was not reportable because the condition was not outside the design basis of the plant.

Upon completion of the engineering supporting analysis, NMPC determined that the RSP was inoperable. Procedure N2-OP-78, "Remote Shutdown System," Revision 10, requires the operators to verify the minimum flow valve position using the VPI at the RSP. Therefore, a loss of the indication would inhibit the operators' ability to place and maintain the reactor in a safe shutdown condition. Since no contingency was included in the procedure, NMPC declared the RSP inoperable as of the date and time the condition was first identified. Additionally, NMPC notified the NRC of the condition in accordance with 10 CFR 50.72. The inspectors considered the identification of the potential for a fire-induced short-circuit to fail the RSP RHR minimum flow VPI, and the recognition that the deficiency adversely impacted the remote shutdown procedure, to indicate a good safety perspective by the licensee.

The Unit 2 UFSAR, Section 9B.8.2.4, states that "Necessary administrative procedures, operating instructions, and Operator training are provided for the main control room and relay room fire event." The failure to have adequate contingency actions for a loss of RHR minimum flow VPI at the RSP is contrary to the description provided in the UFSAR and is considered a violation of 10 CFR 50.59. However, the identification of this issue by the licensee was the result of corrective actions associated with similar problems reviewed during NRC inspection 97-05 which are being considered by NRC management for possible escalated enforcement. This item remains unresolved pending the completion of the NRC's review of items identified in NRC IR 97-05. **(URI 50-410/97-03-03)**

To correct the deficiency, NMPC changed the remote shutdown procedure to provide a minimum flow path for the RHR pumps that was not susceptible to damage during a control room fire. The change also included a lower RHR flow rate until operators could manually close the RHR minimum flow valves, at which time RHR flow would be returned to the previously established rate. This would ensure that, in the event the minimum flow valve failed open, the total demand on the RHR pump would not exceed the pump runout rating. Also included in this procedure change, although not related to the identified deficiency, was a reduction in the minimum allowable system flow to prevent pump damage.

During the review of applicability review (AR) 21767, the inspectors were unable to ascertain the basis for why the reduced RHR flow was acceptable. Discussion with the responsible design engineer indicated that engineering judgement was used to determine that the reduced RHR flow was still bounded by the worst case scenarios for RHR functions. Subsequently, an engineering analysis justified the reduced flow and supported the initial engineering judgement. With respect to minimum system flow, the design engineer was able to provide valid supporting documentation; however, neither the basis, nor a reference to the engineering document for this change, was included in the procedure change. The inspectors considered the documentation to support the procedure change to be weak; in that, additional information from the engineer was required to justify the basis for the changes. Subsequently, the inspectors were informed that the Licensing and Unit 2 Engineering Managers agreed with the inspectors, and they initiated a DER to further evaluate the issue.

Also during the review, the inspectors evaluated the completed remote shutdown procedure change to ensure that the UFSAR emergency lighting requirements were satisfied. The Unit 2 UFSAR, Sections 9B.10 and 9.5.3.3, require 8-hour battery-pack lighting for all areas needed for the operation of equipment necessary for safe shutdown in case of a fire, and in access and egress routes thereto. To complete this evaluation, the inspectors accompanied an off-watch non-licensed operator during an in-plant simulation of the procedure steps that were affected by the change. During the simulation, the inspectors noted that the installed emergency lights were inadequate to properly illuminate the access and egress path, and that no emergency lights were installed in the vicinity of the RHR minimum flow valves.

Upon identification of the inadequate lighting, the inspectors informed the Unit 2 Plant Manager. Subsequently, NMPC established contingencies of pre-staged portable battery operated lights with an 8-hour equivalent capacity for operators required to enter the plant. The inspectors considered the contingency plan to be appropriate. Additionally, the licensee initiated an evaluation to determine the adequacy of installed 8-hour emergency lights for other in-plant actions required by the remote shutdown procedure. The results of this evaluation were not reviewed by the inspectors.

The inspectors reviewed the procedure change evaluation and the 10 CFR 50.59 applicability review associated with the change to Procedure N2-OP-78, and discussed the changes with the responsible Operations Department personnel. Procedure NIP-SEV-01, "Applicability Reviews and Safety Evaluations," Revision 02, is the controlling procedure for AR reviews, and requires the preparer to determine whether the proposed change affects NRC approved plans and programs, including the fire protection program. The AR (21767) indicated that the proposed change did not involve a change to the fire protection program. Procedure NLAP-SEV-0101, "Guidelines for Applicability Reviews," Revision 00, states that changes involving safe shutdown systems (i.e., the remote shutdown panels) impact the fire protection program; and that the AR preparer should contact the owner organization or perform a detailed review. The failure to complete the fire protection program review, as required by Procedure NIP-SEV-01, contributed to the licensee's failure to identify the need for emergency lights to operate the safe shutdown equipment. This is a violation of TS 6.8.1 regarding procedural adherence. **(VIO 50-410/97-03-04)**

c. Conclusions

NMPC's identification of the inadequate RHR minimum flow VPI at the Unit 2 RSP was considered good. Also, the recognition that the deficiency adversely impacted the remote shutdown procedure indicated a good safety perspective by NMPC. However, the failure to have adequate contingency for a loss of the VPI was contrary to the UFSAR requirement to have operating instructions in the event of a control room fire, and was a violation of 10 CFR 50.59. However, pending the resolution of similar issues (see NRC IR 50-220 and 50-410/97-05) being considered by NRC management for possible escalated enforcement, this item remains unresolved. **(URI)** Furthermore, the procedure change to address the deficiency was not reviewed with respect to the fire protection program, as evidenced by the failure of NMPC to identify the inadequate emergency lighting. **(VIO)** Additionally, documented engineering justification for the procedure change was poor, in that additional information from the engineer was required to justify the basis for the change.

O2.2 Tours of Unit 1 During RFO14

a. Inspection Scope

The inspectors conducted routine tours of the Unit 1 reactor and turbine buildings during RFO14, focusing on areas which were normally sealed or inaccessible during power operation.

b. Observations and Findings

The inspectors noted that equipment material condition and compartment housekeeping during the refueling outage were good. The amount of debris and work-related equipment in any specific area was consistent with the ongoing level of maintenance activity. Prior to reactor startup, the inspectors toured areas housing safety-related components, and areas previously noted as having accumulated a significant amount of debris during the outage. No concerns were identified during these tours, indicating an appropriate level of attention to housekeeping by licensee management.

c. Conclusions

Equipment material condition and compartment housekeeping during Unit 1 RFO14 were good and consistent with the ongoing level of maintenance activity. Prior to startup, an appropriate level of management attention to housekeeping was evidenced by adequate plant cleanliness, even areas in which significant debris had accumulated during the outage.

O5 Operator Training and Qualification (71001, 71707)

O5.1 Unit 1 Requalification Training Simulator Observations

a. Inspection Scope

Simulator training is an integral part of the licensed operator requalification training (LORT) program. The inspectors observed a Unit 1 control room crew during their simulator evaluation; this included a review of the simulator scenario, and an assessment of the NMPC evaluation of the shift's performance.

b. Observations and Findings

Part of a licensee's on-going LORT, as required by Title 10 of the Code of Federal Regulations Part 55 (10 CFR 55), "Operators' Licenses," is to evaluate the licensed operators' ability to effectively deal with various equipment malfunctions and plant transients. On May 5, 1997, the inspectors observed an NMPC evaluation of a Unit 1 operating crew; the evaluation was conducted using the computer-driven control room simulator with a challenging scenario. The scenario (O1-OPS-009-1DT-1-36, Revision 1) began with the plant at 100% power, with one of the

emergency diesel generators (EDGs) running for a surveillance test, and included the following events:

- Tornado alert
- Loss of all offsite electrical power
- Fire in one of the EDGs
- Loss of all control rod drive pumps -- inability to drive control rods
- Manual reactor scram / turbine generator trip

Overall, the operating crew demonstrated satisfactory ability to recognize abnormal conditions, use procedures to analyze and correct deficiencies, and protect the health and safety of the public. However, some weaknesses in the operating crew's performance were identified by the NMPC evaluators, additional weaknesses were identified by the inspectors. The NMPC evaluators identified the following:

- Communications were unacceptable during most of the drill;
- Self-checking was initially acceptable, but deteriorated quickly as the events progressed; and
- Crew updates were vague.

The inspectors identified the following weaknesses:

- After the SSS had assumed the duties of the Emergency Director, the assistant station shift supervisor (ASSS) appeared to request permission from the SSS prior to proceeding with recovery actions;
- The shift technical advisor (STA) used the incorrect power-to-flow map after loss of one reactor recirculation pump; and
- Frequently, the ASSS and SSS were directing activities at the same time, causing confusion as to who was in charge and who was being directed to do what.

Some of the weaknesses identified above are repetitive from previous reviews of operator performance.

The NMPC evaluation team was comprised of trainers, training management, and Unit 1 operations management. Compared to previously observed training evolutions, the inspectors noted that the evaluators were more critical in identifying weaknesses.

c. <u>Conclusion</u>

The performance of a Unit 1 operating crew during a simulator evaluation was acceptable, although several weaknesses were identified by the NMPC evaluators and the NRC inspectors, which indicate a need for continuing emphasis on communication techniques, attention to detail, command and control by shift supervision, and STA knowledge.

O7 Quality Assurance in Operations (40500)

O7.1 Safety Review and Audit Board Observations

a. Inspection Scope

The inspectors attended a periodic NMPC Safety Review and Audit Board (SRAB) meeting. The inspectors observed the SRAB meeting to verify compliance to TS requirements and approved NMPC procedures, to ascertain the scope and content of discussions, and to evaluate the conduct and safety focus of the members.

b. Observations and Findings

The inspectors attended the April 15, 1997, SRAB meeting. The SRAB met the requirements stated in the Unit 1 and Unit 2 TSs and NMPC Procedure NIP-SRE-01, "Safety Review and Audit Board," Revision 00.

An appropriate SRAB quorum was present and verified by the SRAB Chairman. Some of the topics discussed by the SRAB were:

- Review of Site Operations Review Committee meeting minutes
- Reports on Unit 1 and Unit 2 activities and concerns
- Review of Unit 1 and Unit 2 licensee event reports
- SRAB audit reports
- Safety evaluations

The conduct of the meeting was controlled by the Chairman, and all the topics on the scheduled agenda were addressed. Overall, the safety focus of the SRAB was good. The SRAB members had a questioning attitude and were self-critical; the inspectors considered this beneficial in maintaining the proper safety focus.

c. Conclusions

The April 1997 SRAB meeting was well controlled and met the requirements of the Technical Specifications. The members were self-critical, contributing to a proper safety focus.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) URI 50-220/95-23-02: Unit 1 Nitrogen Tank Alarms Inoperable

a. Inspection Scope

In 1995, Unit 1 operators identified that frequent low level alarms on the #12 nitrogen (N_2) tank were due to leakage from a system valve. After the tank was drained for repairs, the low level alarm cleared; but the control room operators failed to notice that the alarm cleared. The next day, an NRC inspector noticed that

neither the low level alarm, nor the low pressure alarm, for the #12 N_2 tank was annunciated.

The inspectors discussed the unresolved item with the Operations Manager and the system design engineer, and reviewed the associated corrective actions.

b. Observations and Findings

Background

In October, 1995, an NRC inspector noted that, even though the #12 N_2 tank was empty for repairs, neither the low level alarm nor the low pressure alarm was annunciated. Prior to draining the tank, the low level alarm was lit. Discussions with the CSO and SSS confirmed that the tank was empty, and that the alarm windows should be annunciated. At that time, two Problem Identification (PID) Reports were generated to initiate troubleshooting and repairs. In addition to the physical problem with the failed alarms, the inspector was concerned with the operators' control board awareness; specifically, that they did not recognize or question the status of the N_2 alarms.

Physical Failure

Investigation by NMPC identified that the vendor manual showed a jumper between two terminals of the alarm unit was missing. Review of earlier revisions of the system drawing indicated that the jumper had never been installed. NMPC initiated two design changes to rewire the alarm units (DDCs 1F00022/23, "Rewire Nitrogen Supply Pressure Loop #11/12"). During the review of the changes, the system engineer identified that a total of five alarm units needed to be modified. Maintenance work orders (WOs) were used for the installation of the jumpers, and post-maintenance testing confirmed that both alarms would annunciate if required. The inspector determined the corrective actions, as detailed in the DDCs, WOs, and the associated applicability review (AR 12477, "Nitrogen Supply Pressure Rewire"), to be adequate.

However, failure of the alarms to function as designed, as described in the Unit 1 UFSAR, Section VII.G.2, is a violation of 10 CFR 50.59. This violation of minor significance is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-220/97-03-05)**

Human Performance Failures

Significant was the fact that the on-shift control room operators failed to recognize that an alarm (low level) had cleared erroneously when the tank was drained and that another alarm (low pressure) failed to annunciate. The inspectors considered this to be a significant weakness; in that, the on-shift personnel were aware that the #12 N_2 tank was empty, but failed to exhibit a questioning attitude with respect to the plant status versus alarm status.

Corrective actions included a brief to all shifts related to management expectations. Unit 1 Operations Reference Note #8, "Panel Monitoring and Annunciator Response," was revised to include the following wording: "While an annunciator is being silenced/acknowledged, the potential exists for a different [annunciator] already in alarm to clear, or for another alarm to annunciate at the same time. To prevent the change in alarm status from going undetected, the responding operator must review all alarm panels when an annunciator is silenced or acknowledged." The inspectors considered the corrective actions for the human performance portion of the issue to be acceptable, and no additional instances have been identified.

c. Conclusion

The absence of both the low level and low pressure alarms at Unit 1 when the #12 N_2 tank was empty is a violation of 10 CFR 50.59. (NCV) Also, in 1995, the control room operators failed to recognize that one alarm had cleared erroneously and another failed to annunciate. The inspectors considered this was a significant weakness with respect to operator performance at that time.

O8.2 (Closed) URI 50-410/95-18-01: Loss of Control Rod Position Indication Following a Reactor Scram

a. Inspection Scope

In September 1995, the Unit 2 operators manually scrammed the reactor in response to increasing main turbine vibration. After the scram, all control rods indicated "Full-In" except for Rod 26-19, which did not indicate for approximately five minutes. The inspectors noted that the same control rod exhibited similar behavior during a scram earlier in 1995. The issue was left as an unresolved item because of the inspectors' concerns that a position indication problem could be an added challenge for the operators during a plant transient. The inspectors also had a concern that corrective action for the initial problem was not aggressively pursued earlier in the year.

The inspector reviewed maintenance records, operator logs, station procedures, and discussed the issue with station personnel to determine the validity of the inspectors' concerns.

b. Observations and Findings

The control rod drive mechanism (CRDM) and position indication probe (PIP) for Rod 26-19 were replaced in November 1993 because of high CRDM seal temperatures. Since that time, on three different occasions, the full-in position indication for that rod did not display immediately following a reactor scram. The three occasions are discussed below:

- June 1995: following a reactor scram, a DER and WO were written to document a multiple control rod notching issue with Rod 26-19 that was discovered during plant start-up. The documentation also addressed the lack

of full-in position indication during the recent scram. No corrective actions were taken at that time as the condition was considered acceptable by the licensee.

- September 1995: following a reactor scram and subsequent loss of the full-in position indication, a DER was written to develop and track the corrective actions for Rod 26-19. A WO was written and documented the performance of troubleshooting during the year and during RFO5. The troubleshooting activities, in general, eliminated the electrical penetration and rod position information system (RPIS) cabinet as the source of the problem. The problem was believed to be in the drywell. The inspector determined that no troubleshooting had been performed in the drywell on the PIP. However, because the licensee had not observed any problems during three other occasions in which the rod was scrammed, the problem was considered resolved.

- December 1996: following a reactor scram, the full-in position for Rod 26-19 failed to illuminate. The position indication subsequently returned 10 minutes after the scram. A DER was written to document the problem. Corrective actions included re-performing the RPIS trouble shooting and planned replacement of the PIP during the next RFO, scheduled for May 1998. The inspector concluded that these corrective actions were sound. However, the plans were not developed until after the plant had started-up from a forced outage; the work could have been done while the unit was shutdown.

The licensee stated that, during the events above, they had no indication that the rod was stuck, and they had seen proper functioning of the rod position on three other scram situations. Therefore, the inspector reviewed emergency and normal operating procedures to evaluate the potential difficulties associated with loss of rod position indication following a scram, with particular focus on a loss of the full-in indication.

Station personnel stated that most reactor scrams from power result in entry into the reactor pressure vessel (RPV) control portion of the emergency operating procedure (EOPs) based on low reactor water level. Following a successful scram, the operators monitor and trend reactor power in the reactor power (RQ) section of the RPV EOP. The first override statement allows the SSS to exit the EOPs if the rods are verified to be in; as the performance of Rod 26-19 has shown, it has subsequently displayed full-in after several minutes, and the EOP was exited. The second override statement allows the SSS to exit the EOPs based on the existence of the required shutdown margin, with the most reactive control rod full-out and all other control rods fully inserted.

In the scenario of concern, where an additional failure of rod position indication results in another rod not indicating full-in, the RQ leg of the EOP directs the operators to verify additional plant parameters. With no other failures, the RQ leg provides direction to concurrently monitor suppression pool temperature and

attempt to insert control rods. In addition, the reactor pressure leg of the RPV EOP would direct operators to stabilize reactor pressure, and not commence a cooldown until all rods are full-in or until it is verified that the reactor will remain shutdown under all conditions. The inspector determined that Special Operating Procedure N2-SOP-101C, "Reactor Scram," lists methods that can be utilized to verify that the control rods are fully inserted. Operating Procedure OP-101C, "Plant Shutdown," directs verification that all rods are fully inserted, listing several methods to confirm this.

c. Conclusion

The licensee's corrective actions for the initial loss of full-in indication for Control Rod 26-19, following a scram, although not aggressive, were acceptable; however, the corrective actions following the second occurrence were weak. Furthermore, there were three occasions during which additional corrective actions could have been performed to prevent recurrence; but the work control process missed an opportunity to trouble shoot the problem during the last plant shutdown, when the under vessel area was accessible. The current corrective actions appear to be sound. The challenge to the operators for the failure of additional rods to indicate full-in following a scram is not considered significant; EOPs address the issue, training scenarios review the issue, and Control Rod 26-19 performance history has not been indicative of a complete failure to indicate position following a scram.

II. MAINTENANCE [2]

M1 Conduct of Maintenance (61726, 62707)

M1.1 General Comments

Using Inspection Procedures 61726 and 62707, the inspectors periodically observed plant maintenance activities and performance of various surveillance tests. In general, maintenance and surveillance activities were conducted professionally, with the work orders (WOs) and necessary procedures in use at the work site, and with the appropriate focus on safety. Specific activities and noteworthy observations are detailed in the inspection report. The inspectors reviewed procedures and observed all or portions of the following maintenance/surveillance activities:

- N1-ST-026 — Feedwater and Main Steamline Power-Operated Isolation Valves Partial Exercise Test and associated Functional Test of Reactor Protection System Trip Logic
- N1-FST-FPL-SA001 — Low Pressure Carbon Dioxide System Functional Test
- N1-ISP-036-201 — Contact Verification [of one-out-of-two logic array]

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

•	N1-ISP-209-009	Instrument Line Flow Check Valve Operability Check
•	N1-IST-LK-101	Reactor Pressure Vessel and ASME [American Society of Mechanical Engineers] Class 1 System Leakage Test
•	N1-RESP-11	In-Sequence Shutdown Margin Test
•	N1-ST-R1 .	Control Rod Scram Insertion Time Test
•	N1-ST-R2	LOCA [Loss of Coolant Accident] and EDG [Emergency Diesel Generator] Simulated Auto Initiation Test
•	WO 95-4451-00	Troubleshoot Nitrogen Supply Pressure/Flow
•	WO 96-0300/1-00	Rewire Nitrogen Supply Pressure Indicator -- Implementing Design Change for Loop #11/12
•	WO 96-0300/1-01	Rewire Nitrogen Supply Pressure Indicator #11/12 -- Electrical
•	WO 96-0300/1-02	Rewire Nitrogen Supply Pressure Indicator #11/12 -- Instrumentation & Control -- Post-Maintenance Test

M2 Maintenance and Material Condition of Facilities and Equipment (61726, 62707)

M2.1 Hydrostatic Leakage Test of the Unit 1 Reactor Pressure Vessel

a. Inspection Scope

To verify integrity of the reactor pressure boundary, NMPC performed a pressurization test of the system piping and components. The test was conducted at rated pressure for normal operations. The inspectors observed portions of the test, reviewed the test procedures and valve lineups, and the associated TS.

b. Observations and Findings

The hydrostatic pressure surveillance test of the reactor vessel and ASME Class I pressure piping and components was required as part of the post-refueling verification. The test was performed in accordance with Procedure N1-IST-LK-101, "Reactor Pressure Vessel & ASME Class I System Leakage Test," Revision 02, per WO 95-1309-01.

The inspectors discussed the planned evolution with Unit 1 personnel and monitored the joint special-evolution briefing provided by the Operations Manager and the Inservice Test (IST) Supervisor. Being a special evolution, a Senior Manager-in-Charge needed to be designated; in this case, it was the Operations Manager. The procedure required most plant systems to be aligned for power operation. The inspectors reviewed a sample of the system lineup exceptions (allowed by Step 6.3 of Procedure N1-IST-LK-101) and identified none that were required for the current plant condition.

Before the drywell entry to perform a visual examination for leaks, NMPC management was cautious to ensure all personnel entering were qualified and adhered to the procedures for Confined Space Entry (SFT-OSH-107) and Heat Stress (SFT-OSH-0111). The inspectors independently verified that limits for

heat-up rate and pressurization were maintained, in accordance with the procedure. The surveillance test was completed successfully.

c. Conclusion

The Unit 1 hydrostatic test of the reactor vessel and the pressure boundary piping and components was conducted cautiously and with good management oversight. Procedural limits and safety considerations were highlighted during the pre-evolution briefing by senior management. The hydrostatic test was successfully completed.

III. ENGINEERING

E1 Conduct of Engineering (37551)

E1.1 General Comments

Using NRC Inspection Procedure 37551, the inspectors frequently reviewed design and system engineering activities and the support by the engineering organizations to plant activities. Concerns and minor weaknesses were discussed with the appropriate management. In general, engineering activities maintained a good safety focus; specific events and noteworthy observations are detailed in the sections below.

E8 Miscellaneous Engineering Issues (92903, 90712, 92700)

E8.1 (Closed) LER 50-220/97-03: Reactor Water Cleanup Auxiliary Pump Rooms Not Monitored by Thermal Sensors

On April 3, 1997, NMPC determined that thermal sensors used to detect line breaks were not appropriately located in the auxiliary cleanup pump room as described in Section 10.B.3 of the Unit 1 UFSAR. The technical details associated with this licensee event report (LER) were discussed in NRC IR 50-220/97-02. This deficiency was identified by the licensee and immediate corrective actions have been taken to resolve the UFSAR discrepancy. The inspectors considered the LER to be timely and to accurately describe the event. The root cause of the event and immediate corrective actions were adequate, and the long-term corrective actions were appropriate.

E8.2 (Closed) URI 50-410/95-03-03: Unit 2 Appendix J Program

a. Inspection Scope

Appendix J of 10 CFR 50, regarding primary containment leakage testing requires periodic verification that containment penetrations and isolation valves do not exceed allowable leakage rates, as detailed in the TS. Previous review by the inspectors identified two potential weaknesses with respect to a change to the licensee's Appendix J leak test program. The two concerns, potential for declaring

a system inoperable based on incorrect leakage limits and failure to identify the running total leakage rate, were reviewed by the inspectors for compliance with the regulations, TS and station procedures.

b. Observations and Findings

The first concern evolved as the result of a March 1995 revision to the document that delineated the acceptance values for the individual local leak rate tests (LLRT), Engineering Document S20003, "List of Primary Containment Penetrations Requiring Type B and C Leak Test." The values were revised to a standard maximum based on the size and type of valve undergoing testing. However, the individual test procedures (one for each valve and penetration) were not changed to include the revised maximum limits; nor was there a requirement to change the individual procedure, since the new values were more conservative. Following the performance of an LLRT, the SSS must review the data and make an operability determination based on the test results. The inspectors' concern was that an overly conservative decision, with regards to system operability, could have been made because the revised (higher) values were not reflected in the individual test procedures. The potential existed for the SSS to declare a system inoperable unnecessarily. This concern was resolved by the licensee revising all the test procedures to reflect the acceptance values stated in the Engineering Document S20003.

The second concern was that the as-found running total leakage rate could go above the TS limit because of the lack of a tracking mechanism. The inspector determined the potential for this to happen and considered it a weakness in the licensee's management of the program. However, based on review of the LLRT records from RFO4, this did not occur. The running total is now maintained as a requirement in Procedure N2-TSP-CNT-R@003, "Local Leak Rate Test Summary," Revision 00. The procedure requires completion of a summary (running total calculation) following the performance of an LLRT and prior to establishing containment. This procedure change ensures that any condition causing the TS limits to be exceeded is properly identified. The inspector noted that the responsibility to track the running condition of containment integrity is now under the purview of the technical support engineering staff vice the instrument and controls (I&C) group. The inspector also noted that this increased amount of resources for monitoring the Appendix J program was appropriate and considered a program improvement.

c. Conclusions

A review of the Unit 2 10 CFR 50, Appendix J Leak Rate Program, showed that procedures appropriately reflected the established acceptance criteria, and that appropriate means were in place to ensure the TS limit on total leakage is tracked. The reassignment of the responsibility to track total leakage from I&C to Technical Support allowed for increased resources to monitor the Appendix J program, and was considered appropriate.

E8.3 (Closed) URI 50-410/95-01-01: Inadequate Review of Unit 2 EDG Vendor Manual

In January 1995, the Division I and II Unit 2 EDGs were declared inoperable because of erratic behavior caused by an inadequate governor cooling water design. During the repairs, it appeared to the inspectors that NMPC had missed an opportunity to incorporate vendor recommendations into the appropriate procedures. The specific information was an acceptable range for oil temperature and a method for measuring the temperature using a surface pyrometer. The EDGs were manufactured by Cooper-Bessemer, and use a Woodward governor.

During this report period, the inspectors reviewed the DER (2-97-0857) related to the vendor manual recommendations, and discussed the problem with Unit 2 engineering and technical support personnel, including the system engineer. In the DER disposition, NMPC noted that there was no requirement to monitor governor oil temperature; although, NMPC stated, after the fact, that it was prudent to do. In the initial installation section of the vendor manual, when selecting the type of oil, it discusses the expected governor oil temperature during normal operation. The DER states "... one could glean from the installation section of the Woodward section that taking governor oil temperature is perhaps a necessity. Especially, if operating parameters were to change. ... discuss[ions] with Cooper-Bessemer and Woodward ... [determined that] it was never the intent ... to monitor governor oil temperatures during periods of engine operation."

The inspectors considered the clarification of the vendor manual information acceptable.

E8.4 (Closed) URI 50-410/95-18-02: Unit 2 List of Containment Isolation Valves Changed without Incorporation Into the Surveillance Procedure

a. Inspection Scope

In August 1995, Unit 2 engineering personnel added four valves to the list of primary containment isolation valves (CIVs) that must be closed per TS. The change was not coordinated with the operations department and was not incorporated into the surveillance test procedure developed by NMPC to satisfy the TS surveillance requirement for the monthly verification that primary containment isolation valves are shut.

During this period, the inspectors reviewed the DER, the revised procedures and engineering list, and discussed the issue with engineering management.

b. Observations and Findings

Unit 2 Technical Specification Surveillance Requirement (TSSR) 4.6.1.2, states that primary containment integrity shall be demonstrated by verifying, at least once every 31 days, that CIVs are closed. The TSSR was scheduled and accomplished by the performance of Operations Surveillance Test Procedure N2-OSP-CNT-M001, "Primary Containment Penetration Verification Test." The CIVs were listed in

Engineering Document M2-00001, "List of Primary Containment Penetrations Required to be Closed During Accident Conditions Per Technical Specification," Section 3/4.6.1.1.b. Section I.1 of M2-00001 states that the list is to be incorporated into Procedure N2-OSP-CNT-M0001.

On August 7, 1995, engineering supervision approved a change to M2-00001 that added four standby liquid control (SLC) system valves to the list of CIVs. On August 21, the SSS identified noted that the four SLC valves had not been included during the latest performance of the surveillance test; further review revealed that the valves had not been verified closed since May 1995. The SSS immediately verified the valves closed and generated a DER. Subsequently, NMPC determined that the SLC valves were not actually required for primary containment isolation, but were added to the list as an "enhancement." At that time, the inspectors expressed concern that the list of CIVs could be changed before an evaluation by the operations department for impact on the associated surveillance test procedure.

During this inspection period, the inspectors discussed this issue with engineering and operations management, and reviewed the DER (2-95-2415) and associated procedure changes. The DER determined the root cause to be engineering's failure to recognize the distinction between a plant enhancement and a requirement. Corrective actions included a discussion of the issue with the Unit 2 mechanical design engineering personnel reinforcing management's expectations, and removal of the SLC valves from M-00001. In addition, the higher-tier Procedure NIP-DES-04, "List of Controlled Lists," was clarified as to (1) the responsibilities of engineering personnel to notify the end users of the change and (2) the requirement that the associated procedures be updated within two weeks. Nonetheless, the failure to incorporate engineering changes into the associated surveillance test procedure was not in accordance with the licensee's procedures for control of Controlled Lists, and is a violation of TS 6.8.1 regarding procedural adherence. This violation of minor significance is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy. **(NCV 50-410/97-03-06)**

c. <u>Conclusion</u>

Although NMPC ultimately determined that the SLC valves were not CIVs and thus were not required to be included on the Controlled List, a lack of communication between engineering and operations departments resulted in a failure to appropriately include the valves in the surveillance test procedure. The failure to update the surveillance procedure was a violation of an administrative control procedure. (NCV)

IV. PLANT SUPPORT

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

below. Specialist inspectors in the same areas use other procedures during their reviews of plant support activities; these inspection procedures are listed, as applicable, for the respective sections of the inspection report.

R1 Radiological Protection and Chemistry (RP&C) Controls (71750, 83750, 86750)

R1.1 Review of Unit 2 Reactor Water Conductivity

a. Inspection Scope

As a result of the cracking of the core shroud at Unit 1, and the significance attributed to reactor water conductivity, the inspectors reviewed the results of chemistry samples for Unit 2 since initial operation.

b. Observations and Findings

NRC Generic Letter (GL) 94-03, "Intergranular Stress Corrosion Cracking of Core Shrouds [IGSCC] in Boiling Water Reactors," requested licensees to submit a safety analysis supporting continued operation, including information relative to the factors that influence the occurrence of cracking and crack growth. Conductivity of the reactor water is one of the contributing factors for IGSCC. During the refueling outage, NMPC identified cracks along some vertical welds of the Unit 1 core shroud. The cracks were determined to be due to IGSCC.

The NMPC response to GL 94-03, dated August 23, 1994, stated that Unit 2 conductivity has averaged 0.129 μS/cm over five cycles. Based on the fact that Unit 2 had approximately four years of on-line operation and an average conductivity of 0.129 μS/cm at the time of their response, which were less than the guidelines of < 8 years of hot operation and an average conductivity of $\leq$ 0.3 μS/cm, the Unit 2 shroud was classified as Category "A" and no inspection was required at that time. The guidelines and categories are contained in NRC NUREG-1544, "Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components," Table 6.2-1.

The inspectors independently reviewed, and graphed, the conductivity for Unit 2 since initial operation. The graph of Unit 2 conductivity is included as Attachment 3 to this report. Over each calendar quarter, the conductivity was consistently below the limit of 0.3 μS/cm. The inspectors' calculations showed an average of 0.117 μS/cm, including all shutdown periods, which confirmed the NMPC response to GL 94-03.

c. Conclusion

The inspectors' independent calculations verified that the conductivity of the Unit 2 reactor water continues to meet the requirements for a shroud being classified as Category "A" in accordance with NUREG-1544.

R1.2 Unit 1 Refueling Outage Radiation Protection (RP)

a. Inspection Scope

The inspector reviewed radiological controls implementation and RP-related performance during Unit 1 RFO14. The inspector toured Unit.1 radiologically controlled areas (RCAs), and conversed with RP supervision and several RP technicians (RPTs). The inspector also reviewed the licensee's actions regarding an outgoing laundry shipment and its accompanying manifest.

b. Observations and Findings

During a review of RP controls implemented for a hydrostatic test, the inspectors noted that RP/safety briefings were well-focused and complete. Personnel demonstrated very good as-low-as-is-reasonably-achievable (ALARA) awareness. There was a high level of RPT oversight and the technicians were both attentive and supportive. Unit 1 radiological housekeeping was very good. No contamination control inadequacies were identified.

The inspector noted that the licensee would exceed the ALARA goal established for the refueling outage. The inspector's review of this matter determined that this was due to added activities and work scope growth at the end of the outage such as the core shroud vertical weld inspections. ALARA performance on some jobs such as reactor building closed loop cooling support work and CRD exchanges was excellent. For example, in RFO14, CRD replacement and associated work was completed at an average exposure cost of 0.408 person-rem/CRD; in RFO13, the average exposure cost was 0.714 person-rem/CRD. Overall, it was assessed that the ALARA program was well implemented.

Unit 1 Contamination Occurrence Reports from the ongoing refueling outage were reviewed. There were no hot particle contamination events of regulatory concern. No problems in dose assessment methodology were noted, and the program established by the licensee was followed. The inspector assessed that postings and labels were generally established in accordance with the licensee's program. Individuals were wearing the required dosimeters. No discrepancies were identified regarding shipment 97-1078 (laundry shipment). The accompanying manifest was found complete.

c. Conclusions

Despite the fact that it was expected that the ALARA goal for the Unit 1 refueling outage would be exceeded prior to restart, RP controls were being well implemented during the Unit 1 RFO.

R2 Status of RP&C Facilities and Equipment (83750)

R2.1 Calibration of Area Radiation Monitoring Systems, Unit 1 and Unit 2

a. Inspection Scope

Unit 1 and Unit 2 Area Radiation Monitor (ARM) calibration methodology was reviewed. Calibration records for ARMs 1 through 15 were selected at Unit 1. The following ARM calibration records were selected at Unit 2: .

- 2RMS-RE2B Reactor Building, elevation 215 West
- 2RMS-RE116 Turbine Building, elevation 250 Southwest
- 2RMS-RE118 Turbine Building, elevation 261 Northeast
- 2RMS-RE132 Radwaste Building, elevation 265 Southeast
- 2RMS-RE134 Radwaste Building, elevation 261 West
- 2RMS-RE142 Radwaste Building, elevation 279 West
- 2RMS-RE152 Radwaste Building, elevation 240 North
- 2RMS-RE3A Feedwater Heater Bay West
- 2RMS-RE3B Feedwater Heater Bay Middle
- 2RMS-149 Reactor Building, elevation 328, RWCU Valve Room
- 2RMS-150 Turbine Building, elevation 250, Northwest Resin Regeneration
- 2RMS-151 Turbine Building, elevation 306, Low Pressure Turbine

b. Observations and Findings

The inspector noted that the Unit 2 ARM calibration program significantly exceeded American National Standards Institute (ANSI) guidelines. The inspector noted that the Unit 1 ARM calibration program met ANSI guidelines. Through a review of calibration records the inspector assessed that licensee personnel adhered to the calibration practices established at each unit.

c. Conclusions

The Unit 1 ARM calibration program was well implemented. The Unit 2 ARM calibration program significantly exceeded ANSI guidelines.

R2.2 Exposure Controls Associated with Thermex Equipment Operations

a. Inspection Scope

The licensee RP controls regarding the Thermex modular waste water treatment system (Thermex) at both units were reviewed. The inspection consisted of review of radiation surveys and interviews of licensee personnel regarding DERs and Exposure Evaluation Reports (EERs) to evaluate the radiological conditions associated with Thermex operations and resulting personnel exposures. The majority of the review was performed in-office.

b. Observations and Findings

Routine Survey Program Results Provided by Licensee

The inspector's review of licensee radiation surveys taken of the area(s) surrounding each Thermex unit indicated no substantially large variations in the dose rates from survey to survey. Variations that were observed were the result of progressive loading of the filter media in the Thermex units. At times, dose rates increased to the point where the licensee established high radiation area (HRA) controls to gain access to the Thermex unit. At other times, the inspector noted that HRA controls were removed by the licensee after surveys indicated that the radiological conditions no longer warranted such controls, e.g., after filter media change-outs.

RP Controls Pertinent to Thermex Units

All workers entering RCAs were required to wear both an electronic self-reading dosimeter (ESRD) and a Thermoluminescent Dosimeter (TLD), regardless of whether or not the worker would be entering a HRA. Both stations have installed Area Radiation Monitors with a local alarm function to warn of any unexpected change in radiological conditions.

Unusual Occurrences with Dosimeter Indications (near Thermex Units)

The licensee informed the inspector of examples of ESRD failures in which the ESRD failed in a manner such that it might appear to a worker that dose rates had significantly increased when, in fact, radiological conditions and dose-rates had not changed. Occasionally, due to a design deficiency, some ESRDs indicate rapidly increasing dose-rates independent of actual radiological conditions. Previously, the licensee evaluated two cases in which ESRDs failed in this particular manner. This particular ESRD failure mode had previously been demonstrated to the inspector. The inspector determined that there were no issues with regulatory requirements and that the licensee had properly investigated each event of this nature. This assessment was based on the following:

- The licensee was aware of the problem and investigated any ESRD failure under their EER process. No unusual exposures as a result of Thermex operations were identified by the EER process.

- The dose of record was assigned from TLDs. ESRDs were used only as real-time exposure control devices. Worker doses, as measured by TLDs, have been well-within the regulatory annual limit of 5 rems.

- Radiation workers were trained to leave an area and report immediately to RP staff whenever erratic ESRD function was noted or if radiological conditions changed. In each of the two instances noted above, the workers responded correctly to the alarming dosimeter and immediately exited the area and contacted RP staff.

c. Conclusions

No inadequacies in RP controls applied to the Thermex system were noted, NMPC properly followed-up on ESRD problems, and TLD data indicates no exposures in excess of NRC regulatory limits.

R7 Quality Assurance (QA) in RP&C Activities (84750)

R7.1 Radiation Protection Assessment Activities

a. Inspection Scope

Radiation assessment activities were reviewed, including: fifteen QA surveillances, RP department self-assessments, whole body counting quality control (QC), and outage-related DERs.

b. Observations and Findings

The inspector reviewed 15 QA surveillances during the Unit 1 RFO and noted that QA oversight of RP performance was comprehensive. In many instances, QA recorded RP-related observations even if the particular surveillance was not directed to RP program performance. The inspector noted that RP self-assessments were a good initiative and a good tool for augmenting QA audits/surveillances. These assessments were conducted by RP department staff and were used to assess and provide immediate feedback to station workers on their radiation worker practices. The inspector assessed that QC for Unit 1 and Unit 2 whole body counting was very good. The inspector noted that a proper level of attention was placed on DERs depending on their significance and complexity. It was also noted that corrective actions were both timely and reasonable for the DERs reviewed.

c. Conclusions

Those aspects of the QA program reviewed were well-implemented.

S1 Conduct of Security and Safeguards Activities (81700)

S1.1 General Comments

a. Inspection Scope

Determine whether the security program, as implemented, met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. Areas inspected included: previously identified items, effectiveness of management controls, management support and audits, alarm stations and communication, and training and qualification.

b. Observations and Findings

Two previously identified items involving inadequate vehicle searches and marginally effective assessment aids were closed. However, a violation of NRC requirements was identified in the area of access control of vehicles. Management support was evident by the replacement of 24 monitors in the alarm stations to enhance the effectiveness of the assessment aids, procurement of new weapons to enhance tactical response capabilities, and adequate security staffing levels for effective program implementation. Alarm station operators were knowledgeable of their duties and responsibilities and improvements were noted in the quality of the protected area assessment aids.

Security training was being performed in accordance with the NRC-approved training and qualification (T&Q) plan and management controls for identifying, resolving, and preventing programmatic problems appeared to be effective as demonstrated by a minimal number of logged and reported security-related events.

c. Conclusions

The inspector determined that, in general, the licensee was conducting its security and safeguards activities in a manner that protected public health and safety and that the program, with the exception of protected area access control of vehicles, met the licensee's commitments and NRC requirements.

S1.2 Improper Use of Access-Controlled Vehicles

The inspector reviewed Section 4.11 of the Plan, Revision 5, dated April 18, 1996, titled, "Access Controls - Vehicles." Since the UFSAR does not specifically include security program requirements, the inspector compared licensee activities to the NRC-approved physical security plan, which is the applicable document. The inspector determined, based on discussions with security supervision and reviews of applicable procedures and records, that designated licensee vehicles were not being controlled as required in the Plan or applicable procedures.

Specifically, the Plan, states that designated vehicles may only exit the protected area for reasons of operational necessity, maintenance, repair, security or emergency. Additionally, Security Procedure 3.3, titled, "Vehicle Access Control," Section 7.25, Revision 16, dated February 7, 1997, states that all vehicles listed on the current Designated Vehicle List, regardless of ownership, are considered site vehicles and may leave the protected area only for the following reasons: operational necessity (i.e., mail runs, warehouse runs, snow removal, etc.), maintenance, security, emergency, or repair of vehicle.

However, on April 10, 1997, the inspector identified four licensee designated vehicles listed on the licensee's designated vehicle list that were being maintained outside the protected area for reasons other than operational necessity, maintenance, repairs, security, or emergencies. This is a violation of NRC requirements. **(VIO 50-220/97-03-07 and 50-410/97-03-07)**

S1.3 Positive Fitness-for-Duty Test for a Contract Supervisor

On March 13, 1997, a contract individual who was fulfilling a supervisory position at Nine Mile during outage maintenance activities tested positive during a mandatory retest. The first sample, collected as part of routine fitness-for-duty screening for initial testing, appeared hydrated. As required by procedure, the retest sample was collected under observation. After the retest sample was confirmed positive by the medical review officer, the individual was escorted from site and access was terminated. The licensee reviewed all work performed by the individual and determined that it was all acceptable; no personnel were actually supervised by the individual. NMPC's actions, including notification of the NRC resident inspectors, were timely and in accordance with the requirements of 10 CFR 26.

S2 Status of Security Facilities and Equipment (81700)

S2.1 Alarm Stations and Communications

a. Inspection Scope

Determine whether the Central Alarm Station (CAS) and Secondary Alarm Station (SAS) were: (1) equipped with appropriate alarm, surveillance and communication capability, (2) continuously manned by operators, and (3) used independent and diverse systems so that no single act can remove the capability of detecting a threat and calling for assistance, or otherwise responding to the threat, as required by NRC regulations.

b. Observations and Findings

Observations of CAS and SAS operations verified that the alarm stations were equipped with the appropriate alarm, surveillance, and communication capabilities. Interviews with CAS and SAS operators found them knowledgeable of their duties and responsibilities. The inspector also verified through observations and interviews that the CAS and SAS operators were not required to engage in activities that would interfere with the assessment and response functions, and that the licensee had exercised communication methods with the local law enforcement agencies as committed to in the Plan. During a previous inspection conducted in January 1996, the inspector noted some minor problems relative to assessment aid capabilities. To address the concern, the licensee replaced 24 monitors in the alarm stations to enhance the effectiveness of the assessment aids. During this inspection, the inspector evaluated the effectiveness of the assessment aids, by observing on closed circuit television, a walkdown of the protected area. The inspector determined that the assessment aids in both alarm stations were effective and picture quality had improved due to the replacement of the monitors.

c. Conclusion

The alarm stations and communications met the licensee's Plan commitments and NRC requirements.

S5 Security and Safeguards Staff Training and Qualification (81700)

S5.1 Security Program Training and Qualification

a. Inspection Scope

Determine whether members of the security organization are trained and qualified to perform each assigned security-related job task or duty in accordance with the T&Q Plan.

b. Observations and Findings

The inspector met with the security training specialist and discussed training initiatives associated with enhanced contingency response drills and tactical response training, and observed a training film, produced by the training department, on proper room entry techniques. Additionally, the inspector reviewed documentation associated with the performance of contingency response drills and noted that 191 drills were conducted in 1996 and 31 drills were conducted during 1997, as of the time of the inspection.

The inspector randomly selected and reviewed T&Q records for ten security force members (SFMs). Physical and firearms requalification records were inspected for armed SFMs and security supervisors. The inspector found that the training had been conducted in accordance with the T&Q Plan and was properly documented. Additionally, the inspector interviewed a number of SFMs to determine if they possessed the requisite knowledge and ability to carry out their assigned duties.

c. Conclusions

The inspector determined that training had been conducted in accordance with the T&Q plan and that the number and nature of contingency response drills were appropriate. Based on the SFMs responses to the inspector's questions, as well as inspector observations, the training provided by the security training staff was considered effective.

S6 Security Organization and Administration (81700)

S6.1 Management Support of the Security Program

a. Inspection Scope

Conduct a review of the level of management support for the licensee's physical security program.

b. Observations and Findings

The inspector reviewed various program enhancements made since the last program inspection, which was conducted in January 1996. These enhancements included the replacement of 24 monitors in the alarm stations and the procurement of new weapons to enhance tactical response capabilities. In addition, security staffing levels were determined to be adequate for effective program implementation. The inspector reviewed the Security Manager's position in the organizational structure and reporting chain. The Security Manager reports to the Vice-President Nuclear Safety and Support, who reports directly to the Executive Vice-President and Chief Nuclear Officer. Additionally, the inspector noted that the access authorization program, being safeguards related, reports directly to the Security Manager.

c. Conclusions

Management support for the physical security program was determined to be effective. No problems with the organizational structure that would be detrimental to the effective implementation of the security and safeguards programs were observed or reported.

S7 Quality Assurance in Security and Safeguards Activities (81700)

S7.1 Effectiveness of Management Controls

a. Inspection Scope

Determine if the licensee has controls for identifying, resolving and preventing programmatic problems.

b. Observations and Findings

The inspector reviewed the licensee controls for identifying, resolving, and preventing security program problems. These controls included performance of a departmental self-assessment program titled, "Commitment To Excellence Program" and the performance of the NRC-required annual QA audits. The licensee also utilizes industry data, such as violations of regulatory requirements identified by the NRC at other facilities, as criteria for self-assessment. The inspector reviewed documentation applicable to the performance of the self-assessment program and noted that 66 self-assessment audits were conducted during 1996 and 13 self-assessment audits were conducted during 1997 as of the time of the inspection. The inspector determined, based on a review of the safeguards event logs and self-assessment audit findings, that performance errors were minimal.

c. Conclusions

The inspector concluded that controls were effectively implemented and in a timely manner, to prevent and resolve potential weaknesses.

S7.2 Audits

a. Inspection Scope

Review the licensee's QA report of the NRC-required security program audit to determine if the licensee's commitments as contained in the Plan were being satisfied.

b. Observations and Findings

The inspector reviewed the 1996 QA audit of the security program, conducted in April 1996, (Audit No. 96006). The audit was found to have been conducted in accordance with the Plan. To enhance the effectiveness of the audit, the audit team included two independent security specialists. The audit report identified eight security DERs. Four DERs involved the security department's failure to update, review or document procedural changes, two DERs addressed control of safeguards information, one DER addressed security's failure to properly obtain visitor access authorization, and one DER addressed the acceptance of vendor calculations, by engineering, for the vehicle barrier system. The inspector noted, while reviewing the audit's executive summary, that the audit team's Technical Specialist stated that the program for control and protection of safeguards information was considered to be outstanding in both development and implementation. However, the inspector questioned the Technical Specialist's statement based on the above noted DERs involving the control of safeguards information. To evaluate the effectiveness of the licensee's safeguards control program, the inspector inspected safeguards containers and storage locations, reviewed applicable documentation and implementing procedures, and interviewed security supervision responsible for program implementation. Based on the results of the inspector's observations, discussions and procedural reviews, the inspector determined that the licensee's program for the control of safeguards information was effective and satisfied the licensee's commitments and NRC requirements. The DERs were not indicative of programmatic weaknesses but, if corrected, would enhance program effectiveness. The audit results had been disseminated to the appropriate levels of management. The inspector determined, based on discussions with security management and a review of the responses to the DERs, that the corrective actions were effective.

c. Conclusions

The review concluded that the audit was comprehensive in scope and depth, that the findings were appropriately distributed and addressed and that the audit program was being properly administered.

S8 Miscellaneous Security and Safeguards Issues (92904)

S8.1 (Closed) IFI 50-220/96-03-01 & 50-410/96-03-01: Vehicle Access Control

The licensee's vehicle search requirements exempted the engine compartment for cab-over-engine vehicles from protected area entry search requirements. Although

the exemption existed in the licensee's NRC-approved Physical Security Plan, the NRC considered such a practice a potential weakness that could adversely impact safe operation of the station. The inspector reviewed Revision 5 of the licensee's NRC-approved physical security plan, which retracted the previous exemption. The inspector also reviewed revisions to the security vehicle access procedure and training lesson plans and noted they reflected the retraction.

S8.2 (Closed) IFI 50-220/96-03-02 & 50-410/96-03-02: Assessment Aids

During Inspection 96-03, conducted in January 1996, the inspector determined based on observations, that several monitors in the alarm stations displayed poor picture quality. Additionally, the inspector evaluated the effectiveness of the assessment aids by observing a walkdown of the protected area barrier via closed circuit television in the alarm stations. The inspector determined, based on reviews of applicable documentation and observations (see Section S2.1 of this report), that the corrective actions implemented by the licensee to address the above noted issues were reasonable, complete, and appeared to be effective.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Fire Protection Surveillance Test on Low Pressure Carbon Dioxide System

a. Inspection Scope

The inspectors observed NMPC fire protection staff conduct a routine surveillance test on the low pressure carbon dioxide (Cardox) fire suppression system for the Unit 1 emergency diesel generator (EDG) rooms.

b. Observations and Findings

On April 21, 1997, the inspectors observed a fire protection surveillance test on the Unit 1 Cardox system associated with both EDG rooms. The inspectors verified that the licensee staff conducted the surveillance test using the most recent revision of NMPC Procedure N1-FST-FPL-SA001, "Low Pressure Carbon Dioxide System Functional Test." The inspectors noted that the staff was knowledgeable regarding the scope and purpose of the surveillance test. Communications were very good between the local operators and the Unit 1 control room, in that each procedural step was conveyed and acknowledged using three-part communication.

During the surveillance test, the only discrepancy identified was a leaking mechanical joint. The supervisor in charge of the evolution generated a PID to address the leak.

c. Conclusion

Fire protection staff performance of a Cardox system functional surveillance test on Unit 1 EDGs was good. The staff was knowledgeable regarding the scope and

purpose of the surveillance test. Communications between the local operators and the Unit 1 control room were very good.

F2.2 Emergency Lights Inadequate to Meet Appendix R Requirements

a. Inspection Scope

NMPC identified, during a review of Unit 1 emergency lighting, that numerous areas within the plant were not adequately illuminated by emergency battery lights, as required by the UFSAR and 10 CFR 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities."

The inspectors reviewed the event notification, associated DERs, and Unit 1 UFSAR; and discussed the discrepancies with station staff and management. Also, the inspectors questioned whether similar conditions could exist with emergency lighting at Unit 2, considering some of the battery packs are of a similar type.

b. Observations and Findings

During a review of the 10 CFR 50, Appendix R emergency lighting requirements, NMPC identified that many areas within Unit 1 did not have the appropriate illumination, as required by 10 CFR 50, Appendix R, and the Unit 1 UFSAR, Section 10A, "Fire Hazards Analysis," and Section 10B, "Appendix R Safe Shutdown Analysis." The failures involved:

- the absence of battery powered lighting for general access and egress routes, for evacuation of the plant, for operation of equipment required for safe shutdown as described in special operating procedures (SOPs) and damage repair procedures (DRPs).

- several areas had general lighting but no dedicated emergency lights for specific tasks identified in SOPs and DRPs.

- some battery packs had three or four light heads attached, the packs were analyzed for two heads.

- many emergency lights were mis-directed or had obstructions of the lighting paths.

The above deficiencies were documented on DER 1-97-1378 on May 2, 1997. On May 13, NMPC determined that the above conditions were outside of design basis, and needed to be reported to the NRC in accordance with 10 CFR 50.72. Temporary compensatory actions were implemented -- i.e., hand-held sealed-beam flashlights were in sufficient quantities and were pre-staged.

The inspectors questioned whether the emergency lighting inadequacies at Unit 1 had the potential for a similar concern at Unit 2. NMPC informed the inspectors that Unit 1 battery packs are of several types, while Unit 2 uses the B-200 type

exclusively, and that the Unit 2 battery packs were scheduled to be tested at a later date. Based on questions from the inspectors, NMPC determined the failure rate of the Unit 1 emergency lights, by battery pack type. The results are:

Unit 1 Emergency Lights	B-200	other types
Tested - 169 total	48	121
Failed - 47 total	6	41
% failed:	12.5%	34%

Based on the failure rate of B-200 battery packs at Unit 1, NMPC accelerated the schedule for testing of the emergency lights at Unit 2. As of the end of the inspection period, not all of the emergency battery packs had been tested at Unit 2; but 55 of the 310 tested failed, for a failure rate of 18%. NMPC initiated an adverse trend DER (2-97-1602) for engineering evaluation and corrective action.

Once known, NMPC's corrective and compensatory actions were acceptable; although, the inspectors identified two weaknesses during their reviews. (1) The Unit 1 emergency lighting system was not initially evaluated for operability because the DER process did not require the SSS to consider equipment operability unless the equipment was related to Technical Specification requirements; and (2) the condition was not originally determined to be reportable. Furthermore, the failure to have emergency lighting appropriately installed, in accordance with the Unit 1 UFSAR, is a violation of 10 CFR 50.59. This licensee-identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-220/97-03-08)**

c. Conclusion

NMPC's actions for numerous missing and/or failed Appendix R emergency lights were acceptable. But weaknesses were identified with respect to operability determinations for equipment not addressed in the Technical Specifications; and the length of time required to recognize that the condition was reportable. The failure to have the lights installed in accordance with the UFSAR was a non-cited violation.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

At periodic intervals, and at the conclusion of the inspection period, meetings were held with senior station management to discuss the scope and findings of this inspection. The exit meetings for specialist inspections were conducted upon completion of their onsite inspection:

- Security — April 11, 1997
- Radiological Controls — May 2, 1997

The final exit meeting occurred on June 20, 1997. During this meeting the resident findings were discussed. NMPC did not dispute any of the inspectors findings or conclusions. Based on the NRC Region I review of this report, and discussions with NMPC representatives, it was determined that this report does not contain safeguards or proprietary information.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Niagara Mohawk Power Corporation

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

Attachment 1 (cont'd)

INSPECTION PROCEDURES USED

IP 37551:	On-Site Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71001:	Licensed Operator Requalification Program Evaluation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 81700:	Physical Security Program for Reactor
IP 83750:	Occupational Radiation Exposure Control
IP 86750:	Solid Radioactive Waste Management and Transportation of Radioactive Materials
IP 90712:	In-Office Review of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92700:	Onsite Followup of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

Attachment 1 (cont'd)

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

50-410/97-03-03	URI	Failure to Provide Contingency Actions for Loss of RHR VPI at the Unit 2 Remote Shutdown Panel
50-410/97-03-04	VIO	Inadequate Remote Shutdown Procedure Change Review
50-220 & 50-410/97-03-07	VIO	Improper Use of Access-Controlled Vehicles

CLOSED

50-410/95-01-01	URI	Inadequate Review of Unit 2 EDG Vendor Manuals
50-410/95-03-03	URI	Unit 2 Appendix J Program
50-410/95-18-01	URI	Loss of Control Rod Position Indication Following a Reactor Scram
50-410/95-18-02	URI	Unit 2 List of Containment Isolation Valves Changed Without Incorporation into the Surveillance Procedure
50-220/95-23-02	URI	Unit 1 N_2 Tank Annunciators Inoperable
50-220 & 50-410/96-03-01	IFI	Vehicle Access Control
50-220 & 50-410/96-03-02	IFI	Assessment Aids
50-220/97-03-01	VIO	Failure to Change a Unit 1 Procedure Prior to Proceeding
50-220/97-03-02	NCV	Failure of Unit 1 Operators to Adhere to Procedurally Defined Heavy Load Path During Movement of a Tie-Rod Assembly
50-220/97-03-05	NCV	Failure of Unit 1 N_2 Control Room Annunciators to Function as Designed
50-410/97-03-06	NCV	Failure to Incorporate Engineering Design Changes into the Associated Unit 2 Surveillance Procedures
50-220/97-03-08	NCV	Failure to Have Emergency Lighting Units Installed per the Unit 1 UFSAR
50-220/97-03	LER	Reactor Water Cleanup Auxiliary Pump Rooms Not Monitored by Thermal Sensors

UPDATED

none

LIST OF ACRONYMS USED

ALARA	As Low As is Reasonably Achievable
ARM	Area Radiation Monitor
AR	Applicability Review
ASME	American Society of Mechanical Engineers
ASSS	Assistant Station Shift Supervisor
BWR	Boiling Water Reactor
CAS	Central Alarm Station
CFR	Code of Federal Regulations
CIV	Containment Isolation Valves
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
DBG	Double Blade Guide
DER	Deviation/Event Report
DRP	Damage Repair Procedure
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EER	Exposure Evaluation Report
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESRD	Electronic Self-Reading Dosimeter
GE	General Electric
GL	Generic Letter
HPCS	High Pressure Core Spray
HRA	High Radiation Area
I&C	Instrument and Controls
IFI	Inspector Followup Item
IGSCC	Intergranular Stress Cracking Corrosion
IR	Inspection Report
ISEG	Independent Safety Engineering Group
IST	Inservice Test
LCO	Limiting Condition for Operations
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LORT	Licensed Operator Requalification Training
LPCI	Low Pressure Coolant Injection
MOV	Motor Operated Valve
mrem/hr	millirem/hour
NCV	Non-Cited Violation
NMPC	Niagara Mohawk Power Corporation
NRC	Nuclear Regulatory Commission
PID	Problem Identification
PIP	Position Indication Probe
ppb	parts per billion
QA	Quality Assurance

Attachment 1 (cont'd)

QC	Quality Control
RBEDT	Reactor Building Equipment Drain Tank
RCA	Radiologically Controlled Area
RFO	Refueling Outage
RHR	Residual Heat Removal
RP	Radiation Protection
RP&C	Radiation Protection and Chemistry Controls
RPIS	Rod Position Information System
RPT	Radiation Protection Technician
RPV	Reactor Pressure Vessel
RRP	Reactor Recirculation Pump
RSP	Remote Shutdown Panel
RT	Radiographic Testing
RVWL	Reactor Vessel Water Level
RWP	Radiation Work Permit
SAS	Secondary Alarm Station
SFP	Spent Fuel Pool
SFM	Security Force Member
SLC	Standby Liquid Control
SOP	Special Operating Procedure
SORC	Station Operations Review Committee
SRAB	Safety Review and Audit Board
SRO	Senior Reactor Operator
SSS	Station Shift Supervisor
STA	Shift Technical Advisor
TS	Technical Specification
T&Q	Training and Qualification
TLD	Thermoluminescent Dosimeter
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
VPI	Valve Position Indication
WO	Work Order
μS/cm	micro Seimens per centimeter

Attachment 2

BWR Chemistry Guidelines EPRI TR-103515-R1	Action Levels 1	2	3
Operational Condition: Cold Shutdown (<200°)			
Conductivity (μS/cm)	>2.0	---	---
Chloride (ppb)	>100	---	---
Sulfate (ppb)	>100	---	---
Operational Condition: Startup/Hot Standby (≥200° to ≤10% power)			
Conductivity (μS/cm)	---	>1.0	>5.0
Chloride (ppb)	---	>100	>200
Sulfate (ppb)	---	>100	>200
Dissolved Oxygen (ppb)	>300		
Operational Condition: Power Operation (>10% power)			
Conductivity (μS/cm)	>0.3	>1.0	>5.0
Chloride (ppb)	>5	>20	>100
Sulfate (ppb)	>5	>20	>100

μS/cm = micro Siemen per centimeter / ppb = parts per billion

The EPRI recommended corrective actions associated with the above Action Levels are summarized below:

Action Level 1:

Corrective action shall be taken to reduce the parameter below the Action Level 1 value as soon as possible. If the parameter is not reduced below the Action Level 1 value within 96 hours, a program and schedule for implementing corrective actions shall be submitted to management for review.

Action Level 2:

As soon as practical, corrective actions shall be initiated to reduce the parameter below the Action Level 2 value. If the parameter has not been reduced below the Action Level 2 value within 24 hours, an orderly unit shutdown shall be initiated and the plant brought to cold shutdown as rapidly as operating conditions permit. Following the shutdown, appropriate corrective actions shall be taken before the unit is restarted.

Action Level 3:

If Action Level 3 is exceeded, an orderly unit shutdown shall be initiated immediately. Action shall be taken to reduce the parameter to below Action Level 3 value as quickly as possible. Temperature shall be reduced to <200°F.

ATTACHMENT 3

Unit 2 Conductivity