U.S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee: Niagara Mohawk Power Corporation

Facility: Nine Mile Point

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ATTACHMENT

EXECUTIVE SUMMARY

Nine Mile Point Units 1 and 2
NRC Inspection Report Nos. 50-220; 50-410/97-80

Operations

- The procedures for implementing the corrective action program and operability determination were generally good with some shortcomings noted. The use of the validation test for root cause and corrective actions was considered a good aid for verifying the quality of proposed corrective actions.

- In general, the licensee analyzed and resolved problems. However, shortcomings were identified with the quality of root cause determinations, corrective actions and documentation. Root causes and apparent root causes were generally good at identifying the first level, technical causes but tended to stop and not go to a greater depth. Therefore what was necessary to prevent recurrence was not always fully developed. Several weaknesses in the programs to identify and address human performance issues were apparent. Self assessment and quality assurance activities were generally effective and improvement in these areas was noted.

- A violation was identified concerning the failure to justify the extension of deviation/event report (DER) due dates. Furthermore, the licensee's corrective actions to prevent recurrence of this previously identified concern were ineffective.

Maintenance

- The licensee was effective in resolving emergent maintenance issues including the Unit 2 reactor coolant system flexible hose failure, the Unit 2 service water makeup control valve to the circulating water system malfunction, and the Unit 2 emergency diesel generator DC control power annunciator failure. The operations department made significant contributions both to the identification of problems and control of plant conditions to support maintenance. An inspector followup item concerning the failed flex hose was documented in a separate NRC inspection report No. 50-410/97-06.

- The overall material condition of Unit 2 was good; however, inspector identification of several material problems in the reactor building indicated that additional material inspections by the licensee could be productive. The material condition of the steam tunnel was assessed to be poor. Based on the material deficiencies that were identified by the inspectors in this area, it did not appear that the licensee was taking full advantage of the forced outage to inspect normally inaccessible areas of the plant for emergent material problems.

- Drywell cleanliness was generally good; however, cleanliness requirements for the drywell are not clearly established in the governing procedure especially with respect to control of downcomer foreign material exclusion covers.

Executive Summary (cont'd)

- Given the safety significant functions performed by the "B" residual heat removal system full flow test valve, licensee investigation of the reported degraded condition of the valve was slow. Additionally, the decision to start the 72 hr LCO at 11:00 a.m. on August 19, rather than on the afternoon of August 18, when the condition was reported, was not conservative. The intermediate valve position indication that occurred in June 1997 was apparently a missed opportunity to identify the loose stem lock nut.

- The temporary modification that installed a urethane seal on the Unit 2 inner steam tunnel door in 1992 was inadequate, in that it failed to account for environmental temperatures that exceeded the design temperature of the seal material. After seal degradation was identified, corrective actions were appropriate. Use of the inappropriate seal material from 1992 until 1996 had the potential to cause a failure of secondary containment; however this did not occur, and the degraded condition did not constitute a violation of any other specific regulatory requirements. Operability of the door as a fire barrier was not affected by the degraded seal.

- The problem identification (PID) system procedures established adequate guidance for work control. However, the PID process does not procedurally ensure the same level of review and evaluation as does the DER entry mechanism for the corrective action program.

- Adequate procedures and processes are in place for identification and correction of operator work arounds. Unit 2 has been effective in reducing the number of operator work arounds and longstanding tagouts. Some items being carried on the Unit 2 operator work around list apparently have no recourse remaining, and could lessen the credibility of this corrective action mechanism.

Engineering

- The quality of safety evaluations reviewed was good. The improvement in quality was attributed in part to good senior management oversight of the program. In contrast to the quality of the safety evaluations, the quality of applicability reviews was mixed primarily due to the level of documentation. In some cases, documentation was not sufficient to support the conclusions reached.

Report Details

Overview

Through the review of several licensee programs, performance indicators, material condition deficiencies and discussions with licensee personnel, the inspectors evaluated the effectiveness of the licensee's controls for identifying, resolving, and preventing issues that degrade the quality of plant operations and safety. The objective of the inspection was to determine if the licensee's corrective action program resulted in problems getting resolved.

I. OPERATIONS

O3 Operations Procedures and Documentation

O3.1 Corrective Action Program Procedures

a. Inspection Scope

The team assessed the licensee's corrective action program procedures to determine whether adequate controls are in place to facilitate an effective program.

b. Findings and Observations

Niagara Mohawk Power Corporation's (NMPC's) corrective action program was controlled by Procedure NIP-ECA-01, "Deviation/Event Report," Revision 11, with additional guidance for deviation/event report (DER) dispositioning provided in Procedure, S-GUI-ECA-0101, "Guidelines for DER Disposition," Revision 00. Although some shortcomings were noted, the implementing procedures for the corrective action program were generally good. Particularly noteworthy was the validation test to verify the quality of proposed corrective actions. Furthermore, the team noted that improved guidance regarding 10 Code of Federal Regulations (CFR) Part 21 reviews was incorporated in Procedure NIP-ECA-01 subsequent to a weakness identified in this area in NRC Inspection Report (IR) 50-410/97-01.

The most significant shortcoming with the licensee's corrective action procedures was that an acceptable length of time to route a DER to the station shift supervisor (SSS) was not specified. Since the initiator may not be fully aware of the impact of a concern with respect to plant conditions, and since the SSS is responsible for making equipment operability determinations, timely routing of DERs to the SSS is critical.

Additional shortcomings with the DER procedures included a lack of guidance on evaluating the extent of the problem, such as verifying other susceptible locations for similar problems. Nominal guidance was provided regarding specific reviews for repeat failure and for the identification of adverse trends. No guidance was provided describing management's expectations regarding the branch managers review of the quarterly DER Trend Report. Further details regarding these shortcomings are provided within the applicable sections of this report.

c. Conclusions

The procedures for implementing the corrective action program were generally good with some shortcomings noted. The use of the validation test for root cause and corrective actions was considered a good aid for verifying the quality of proposed corrective actions.

O3.2 Operability Determination Procedures

a. Inspection Scope

The station shift supervisor is responsible for making decisions concerning operability and may request that the NMPC engineering department provide an analysis to provide technical justification for the decision. The team assessed the adequacy of the licensee's procedures associated with operability determinations by comparing the procedures to the guidance provided in NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and Operability as referred to by Generic Letter 91-18.

b. Findings and Observations

Operability Determinations

The Nine Mile Point Unit 1 (Unit 1) Procedure N1-ODP-OPS-0103, "Equipment Operability Determinations," Revision 00, and Nine Mile Point Unit 2 (Unit 2) Procedure N2-ODP-OPS-0001, "Conduct of Operations," Revision 8, are associated with operability determinations. The procedures were found to be consistent with each other and with the guidance provided in Generic Letter 91-18. The procedures provided the station shift supervision with a checklist to aid in operability determinations and guidance in whether requesting an engineering support analysis (ESA) would be necessary.

During the team's review of DERs, no examples of improper operability determinations were identified. However, as described above, the team noted that the DER procedure lacked positive controls to ensure that DERs would be routed to the station shift supervisor in a timely manner. The team identified one DER (1-97-0002) associated with core spray system design pressure inaccuracies in the UFSAR that took six days from initiation until it reached the SSS. Although the SSS determined that the discrepancy associated with DER 1-97-0002 did not adversely impact system operability, the excessive time for the DER to reach shift supervision failed to meet licensee management expectations.

Engineering Supporting Analysis

The team reviewed NMPC's Engineering Guidelines entitled "Engineering Supporting Analysis," NEG-1E-0006 and NEG-2S-010 for Units 1 and 2 respectively. Both procedures contained essentially the same information and were consistent with Generic Letter 91-18. However, the team noted that the Unit 2 guidelines lacked

information regarding the level of supervision required for approval of ESAs. Discussion with the Unit 2 Engineering Department Manager indicated that the first level supervisor was responsible for ESA approval. The team found this consistent with the guidance for Unit 1 ESA approvals and with the Unit 2 ESAs reviewed. The team found the procedural guidance regarding ESAs appropriate.

c. Conclusions

The procedural guidance regarding operability determinations and ESAs were consistent with the guidance provided in Generic Letter 91-18, and considered appropriate.

O7 Quality Assurance in Operations

O7.1 Review of Deviation/Event Reports

a. Inspection Scope

The team reviewed selected DERs for both units to assess implementation adequacy and technical quality.

b. Findings and Observations

Implementation Adequacy

Some minor implementation discrepancies were noted. These discrepancies were normally administrative in nature and did not impact the quality of the DER. However, the team noted that a relatively large number of DERs were past the due date without procedurally required extension requests, this concern is described in detail in Section O8.1, "Unresolved Item 95-25-03: DERs Extended without Justification."

The DER procedure (NIP-ECA-01) requires the plant managers to categorize DERs with respect to significance. This allows issues of higher significance to receive more stringent evaluation and quicker disposition. The procedures provided a list of examples to aid in determining the appropriate DER category. The team noted at least six cases where DER categorization was questionable. Although the category determined for each case fit examples provided, the team considered the DERs to be better suited to the examples provided for the next higher category.

The questionable categorization was common to two areas. First, DERs associated with potential common mode failure issues (for example DERs 1-97-0565 and 1-97-1482 associated with equipment response to high energy line breaks, and DERs 2-97-0498 and 2-97-1560, associated with recurring failures of a component within the Riley temperature switches as described in Section O7.6), were category 2. The team considered category 1 to be more suitable for these DERs since "common mode failure" was specifically provided in the DER procedure as an example of a category 1 DER. Second, DERs associated with adverse trend (for example DER 2-

97-0203 regarding recurring Unit 2 Operations Department failure to comply with administrative procedures as described in Section O7.6) were category 3; the team considered category 2 to be more suitable based on the extensive nature of the concerns.

Technical Quality

The team reviewed a representative sample of DERs for technical quality, and generally found that problems were analyzed and resolved. However, some shortcomings were identified regarding root cause determination and corrective actions. Concerns associated with root cause analysis are included in Section O7.2. The issues associated with corrective actions include ineffective corrective actions, corrective actions not addressing the root cause, narrowly focused corrective actions, and poorly documented DER dispositions.

Examples of DERs with corrective actions that did not address the root cause included DER 2-96-2155, "QVSA - Adverse Trend 'Chemical Control' violations of NIP-CHE-01," which is described in Section O7 .6, "Adverse Trend Identification." Also, DER 1-97-1439 associated with feedwater low flow control valve leakage illustrated corrective actions not associated with the root cause. Although the licensee determined the leakage not to be excessive, the root cause of the leakage was determined to be component aging; however, no corrective actions were taken to address the aging concern. Furthermore, the closure summary of this DER included a recommendation to reduce the differential pressure across the valve to minimize leakage; but, no means were in place to track this recommendation.

Narrowly focused corrective actions were noted in DERs 2-97-0203, 2-97-0201 and 1-97-1850. DER 2-97-0203: Adverse Trend in Operations Ability to Implement Administrative Requirements, as described in Section O7.6, "Averse Trend Identification," in which the corrective actions only addressed Unit 2 Operations Department, when all departments on site were susceptible to this problem. The corrective actions for DER 2-97-0201 associated with a high frequency of valves found out of position, only addressed Unit 2, when the potential for similar concerns existed at Unit 1. DER 1-97-1850 associated with a control room vent chiller failure, as described in Section O7.2, "Root Cause Analysis," determined the cause of the failure to be the deferral of system periodic preventive maintenance. However, the corrective actions only focused on the chiller that failed, no indication was provided regarding the status of the preventive maintenance for the other division chiller, nor was an evaluation of the impact of deferred preventive maintenance for other equipment available.

In general, the team considered the quality of the documentation associated with DER dispositions to be acceptable. Some of the better documented dispositions provided written answers to the root cause and corrective action validation test described by the licensee's procedure. However, the team considered the documentation of some DERs to be poor. In particular, the disposition for DER 1-97-0697 regarding degraded wiring in an emergency diesel generator (EDG) relay target coil was poor due to the limited information provided. The team discussed

the issues with the relay and controls supervisor, and obtained pertinent information that was not provided within DER disposition. Information, such as, that the similar relays for the EDG were verified not to be degraded, and the programmatic controls in place to allow the licensee to identify similar problems with other relays.

c. Conclusions

In general, the licensee analyzed and resolved problems. However, based on the DERs reviewed, shortcomings were identified in the following areas:

- quality of root cause determinations;
- effectiveness of corrective actions;
- adequacy of corrective actions to address the root cause;
- scope of corrective actions;
- documentation of DER disposition;
- categorization of DERs; and
- extension of DERs without required justification.

O7.2 Root Cause Analysis

a. Inspection Scope

The team reviewed recent root cause evaluations conducted by the licensee. In accordance with station procedures, root cause evaluations are required to be performed on all Category 1 DERs and for other events meeting a licensee established threshold. The team used these reviews to assess the licensee's capability to determine the root cause of events and the effectiveness of the preventive actions assigned to the identified causes at preventing a recurrence.

The team reviewed recent root cause evaluations conducted at each unit.

Unit 1
1-97-1489 - sodium hypochlorite not being injected into waste water
1-97-1501 - failure to write a DER on a non-conforming condition
1-97-1647 - torn screen on condensate demineralizer strainer basket
1-97-1830 - failure of drywell drain isolation valve resulting in plant shut down
1-97-1850 - control room vent chiller failure
1-97-2207 - discrepancy with dose rates for off site shipment

Unit 2
2-97-1570 - blown control power fuses
2-97-1696 - loss of electric power during control room fire
2-97-1698 - primary containment circuit breaker found out of position
2-97-1773 - inadvertent isolation of RWCU system
2-97-1960 - reverse flow failure of check valve 2CSH*V16

In addition, the team interviewed several qualified root cause evaluators and representatives from the quality assurance and training departments.

b. Findings and Observations

The team found that the root cause evaluations in most cases were adequate at determining the higher level, technical causes for an event but did not go into sufficient depth to explore the potential for human error. In some cases, this led the licensee to assigning preventive actions that provided additional procedural or physical barriers to prevent recurrence rather than correcting the underlying human performance issues.

An example is the event and root cause determination documented in DER 1-97-1830. This event led to a plant shutdown as a result of debris found in the seat of a drywell isolation valve. The root cause assigned was failure to maintain adequate foreign material exclusion. The preventive actions assigned included the use of temporary screens during future maintenance activities, increased inspections of floor drain sumps, awareness training, and a revision to the procedure to consider potential impacts of foreign material. The root cause does not discuss why the existing procedural guidance on foreign materials control was inadequate to prevent this event.. There is no evidence that any personnel interviews were conducted to determine why the individuals involved in planning and executing the precipitating work activity did not consider the consequences of their actions.

DER 1-97-1850 was associated with a control room vent chiller. The licensee determined the root cause to be the deferral of periodic preventive maintenance on the system. The root cause evaluation was not thorough, in that information was not provided regarding the adequacy of the deferral decision, or the adequacy of the preventive maintenance deferral process. Furthermore, the licensee's corrective actions were narrowly focused in that an evaluation of the acceptability of the preventive maintenance for the other division chiller was not provided, nor was an evaluation of the impact of deferred preventive maintenance for other equipment completed.

DER 2-95-1850 was associated with a delay in Unit 2 plant startup due to a significant number of non-safety related air-operated valve failures within the condensate demineralizer system. The licensee identified three different types of failures during their review. The team's review of the DER concluded that the licensee failed to identify the underlying cause of the problem, and that the corrective actions were narrowly focused. For example, the licensee determined that a lack of periodic preventive maintenance was a cause, but no reason for the lack of periodic preventive maintenance was provided. Also, the corrective actions were limited to incorporating preventive maintenance for the valves in question, but no consideration was given for the potential for a lack of periodic preventive maintenance on other equipment.

The licensee has self-identified similar inadequacies with the quality of root cause evaluations. These are documented in the Nuclear Quality Assurance department's most recent audit of the corrective action program, NQA Audit 97004, Corrective Action Program. DER C-97-1538 was written based on the audit report finding of a

failure to provide complete root cause evaluations for five of six Category 1 DERs written from February 12, 1997 through May 12, 1997.

c. Conclusion

Root causes and apparent root causes were generally good at identifying the first level, technical causes but tended to stop and not go to a greater depth. Therefore what is necessary to prevent recurrence is not always fully developed.

O7.3 Deviation/Event Report Program Summary Trend Report

a. Inspection Scope

The team reviewed the last four quarterly DER Program Trend Summary Reports to evaluate the usefulness of the reports in assessing the types of problems occurring at the Nine Mile Point (NMP) station, and in the identification of adverse trends at the station. The team discussed the use of the trend reports with the plant managers, and selected branch managers. Also, the team evaluated the accuracy of the information contained within the trend report by comparing DER data to the information provided within the reports.

b. Findings and Observations

The team found the quarterly DER Program Trend Reports contained a large amount of raw data, including, number of DERs sorted by department, cause code and system, number of adverse trend DERS initiated, number of DERs open greater than one and two years, and the number of DER implementation due date extensions sorted by department. The report also included information regarding personnel error rate for each department, in which the error rate was based on work practice cause code per 10,000 hours worked. Although the team considered the amount of information provided within the Trend Report to be significant, no information regarding repeat failures was provided. Furthermore, no assessment of the information was provided.

Through discussion with members of the licensee's senior management, the team ascertained that the licensee's senior management reviewed the Trend Report, and that each branch manager was responsible to review the Trend Report for information pertaining to their respective branch. Since there was no procedural guidance prescribing NMPC's expectation for branch manager review of the Trend Report, the team discussed the assessment of the Trend Report with branch managers from both units. The team noted that the methodology used to assess the Trend Report varied for each branch manager, and that no documented assessment of the Trend Report was required. In general, the branch managers interviewed had reviewed the Trend Reports to determine if their branch was an outlier with respect to the rest of the site. Additionally, all branch managers interviewed noted that the personnel error rate was a valuable indicator of branch performance. The team concluded that although the DER Program Trend Report was reviewed by licensee management, the quality and methodology of the

reviewed varied, and that documented assessment of the data from the DER Program Trend Report was lacking.

The team noted that approximately two percent of all DERs listed in the licensee's database were not assigned the correct category due to data entry errors. Additionally, the team noted that only adverse trend DERs that include the words "Adverse Trend" in the title were included within the DER Program Trend Report. The team discussed this discrepancy with QA and the Plant Managers. Based on these discussions, the team concluded that there was a lack of communication between QA and the plants regarding the adverse trend documentation and trending. Discrepancies with the DER database were noted previously by QA in DER C-97-1611, the specific issues identified by the team were noted by the licensee in DER C-97-2494.

c. <u>Conclusions</u>

The amount of raw data provided within the quarterly DER Program Trend Report was significant; however, no information regarding repeat failures was provided. Although the DER Program Trend Report was reviewed by licensee management, the review varied, and that documented assessment of the data from the DER Program Trend Report was lacking. Data-entry errors associated with DER category were identified. Furthermore, a lack of communications between QA and the units resulted in a failure to trend all adverse trend DERs in the DER Program Trend Report.

O7.4 Corrective Action Program Quality Assurance Audits

a. <u>Inspection Scope</u>

The team reviewed the last three corrective action program audits performed by Quality Assurance (QA) to assess the quality of the findings and the effectiveness of the licensee's actions taken to address identified discrepancies.

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

The Unit 1 and Unit 2 Technical Specifications (TS) required that an audit of the corrective action program be performed every six months. The team verified that the last three corrective action program audits were completed according to the TS requirement.

QA Audit 96008 was completed in May 1996 and concluded that the corrective action program was overall satisfactory with some areas in need of improvement noted. The areas in need of improvement were addressed in two existing DERs (C-94-2560 and C-96-0600); therefore, no additional DERs were generated as a result of the QA audit. The NRC considered that QA Audit 96008 emphasized the findings of previous assessments and provided little independent evaluation. QA's review of corrective action program effectiveness indicated the corrective actions

were effective, however, the team considered the sample size to be too small and narrowly focused on QA identified issues to provide and accurate assessment.

QA Audit 96020 was completed November 1996 and focused on the effectiveness of management's efforts to address previously identified discrepancies related to the corrective action program. Particularly, QA reviewed the effectiveness of the corrective actions taken through DERs C-94-2560 and C-96-0600. In addition, QA reviewed a sample of DERs for compliance and effectiveness of corrective actions. Assessments of the operating experience (OE) process and Branch self-assessments were also included in the audit. QA concluded that the corrective action program was being effectively implemented with some exceptions.

The team found QA Audit 96020 to be more thorough than the previous audit, in that it contained more independent review. However, shortcomings were noted by the team; in particular, QA reviewed 29 significant DERs for compliance with the controlling procedure, but only 3 DERs (C-94-2560, C-96-0600 and 2-95-3187) were reviewed for effectiveness of corrective actions and discrepancies were noted in each case. The team considered the number of items reviewed for effectiveness of corrective actions to be small and the scope of the audit was not increased even though the results indicated that the corrective actions were not completely effective.

The team also noted that the executive summary and the conclusion section of QA Audit 96020 did not reflect the shortcomings described within the details of the audit. This concern was discussed with the QA manager and the Chief Nuclear Officer (CNO) and it was ascertained that the licensee had recognized this and expressed the concern to QA management.

QA Audit 97004 was completed in May 1997 and focused on a review of DERs for administrative and fundamental soundness. Of the 61 DERs reviewed, QA concluded that 62% acceptably implemented the program requirements and that 75% acceptably identified and corrected the underlying cause. The QA audit team concluded that the overall effectiveness and implementation of the CA program was marginally acceptable and that problems existed with DER procedure adherence and root cause determination. As a result of the audit, QA initiated five DERs to address specific concerns, most notable was DER C-97-1680, "Audit 97004: Results of Corrective Actions to Improve Quality of DER Dispositions not in Accordance with Managements' Expectations."

The team considered Audit 97004 to be critical. The review of DERs included a sufficient sample size to provide a credible indication of the overall program status. The checklist used by the QA auditors to evaluate the DERs was found to be good. The separation of the fundamental and administrative soundness, provides the licensee's management the nature and extent of the discrepancies.

The actions taken by the licensee to address concerns identified with the corrective actions program have not been completely effective as evidenced by the recurrent failures to implement DERs in accordance with the procedure, and failures to

adequately identify the underlying cause of problems noted by QA Audits and the NRC team's review of DERs as described in Section O7.1, "Review of Deviation/Event Reports," and Section O7.2, "Root Cause Analysis."

c. Conclusions

Weaknesses were identified in both QA Audits of the corrective action program completed in 1996. The weaknesses included: limited independent assessment, small and narrowly focused samples, and not clearly representing audit findings in the executive summary. Significant improvement in all areas was noted within the latest QA audit, which included a critical assessment of licensee's corrective action program. However, the licensee's corrective actions to address previously identified QA audit weaknesses had not been completely effective as evidenced by recurring discrepancies in implementing the corrective action program and in determining the underlying cause of problems.

O7.5 Operating Experience Review Process

a. Inspection Scope

The team assessed the licensee's process for evaluating operating experience (OE) information including a review of the controlling procedures, and selected OE information.

b. Findings and Observations

NMPC controlled their review of OE through Procedure NIP-ECA-01, "Deviation /Event Report," Revision 11. The procedure allowed for QA, Licensing, and Engineering Departments to determine the applicability of incoming OE information. The responsible departments were required to maintain a record of OE documents received, and to review and document the applicability of the OE information to the NMP station. For OE information found to be applicable to the NMP station, a DER would be initiated for review by the appropriate department. The team considered the licensee's controls for evaluating OE information to be appropriate.

The team reviewed the NMPC Licensing Department records for OE items received in 1997, and the associated statements of applicability. The items were appropriately reviewed and documented. The team also reviewed selected DERs for both units pertaining to NRC Information Notices (INs), General Electric Service Information Letters (SILs), and Title 10 of the Code of Federal Regulations Part 21 notifications, and determined them to be acceptable.

c. Conclusions

The licensee's controls for evaluating OE information were appropriate. The OE-related DERs reviewed were found to be acceptable.

O7.6 Adverse Trend Identification

a. Inspection Scope

The team assessed the licensee's process and effectiveness for identifying adverse trends. Applicable portions of the licensee's procedures, trending information regarding adverse trend DERs and selected adverse trend DERs were reviewed. In addition, the team reviewed the DER history for selected areas in which the potential for an adverse trend existed to determine if adverse trends were properly identified by the licensee.

b. Findings and Observations

Although no guidance is provided within the licensee's procedure controlling the DER process (NIP-ECA-01), the licensee has been initiating DERs for situations where adverse trends were identified. Additionally, a listing of adverse trend DERs was provided in the quarterly DER Program Trend Summary Report. Discussions with the QA manager indicated that the concept of adverse trend DERs as used at the NMP Station is approximately one year old. A review of the trend report indicated that the use of adverse trend DERs had increased over the last year and that most departments were currently involved in the identification of adverse trend DERs.

The team reviewed a list of the adverse trend DERs from July 1, 1996, through August 1, 1997. During that period the licensee initiated approximately 45 adverse trend DERS. The types of issues described by the adverse trend DERS included: equipment issues (13), training issues (5), foreign material exclusion (FME) control issues (2), procedural noncompliance issues (14), DER timeliness and quality-related issues (5), and miscellaneous issues (5).

The team reviewed the thirteen adverse trend DERs associated with equipment issues and noted that five of the DERs were with non-safety-related equipment. Another five DERs were associated with the Unit 2 safety-related unit coolers performance test problems. The five adverse trend DERs associated with the coolers were reviewed by the team and considered to be technically sound with good justifications to support adequacy of the root cause and proposed corrective actions as provided in the form of validation test questions described in the DER procedure. However, three of the five DERs were approximately one month late for disposition without an extension. Further discussion regarding DER extensions is provided in Section O8.1 of this report.

The team reviewed two of the fourteen adverse trend DERs associated with procedural noncompliance. DER 2-97-0203, "Adverse Trend in Operations Ability to Implement Administrative Requirements," was generated as a result of a Unit 2 Operations Department self-assessment. Although no formal root cause analysis of the issue was completed, the team considered the apparent cause determination to be thorough, and the proposed corrective actions to be sound. However, the licensee's review and proposed corrective actions focused only on Unit 2

Operations Department. The team considered this to be narrowly focused, as evidenced by the significant number of other adverse trend DERs associated with procedural noncompliance issues.

The second procedure noncompliance-related adverse trend DER the team reviewed was DER 2-96-2155, "QVSA - Adverse Trend 'Chemical Control' violations of NIP-CHE-01." This DER noted nine DERs from April 4, through September 10, 1996, associated with Unit 2 failures to implemented Procedure NIP-CHE-01, "Chemistry Control Program." The teams's review of DER 2-96-2155 noted that the root cause of inadequate corrective actions to previously identified problems was not addressed as part of the corrective actions. Furthermore, based on the limited information provided within the DER, the team was unable to assess the proposed corrective actions.

The team reviewed the DER history of selected areas in which the potential for an adverse trend existed to assess the licensee's performance in identifying adverse trend conditions. The areas selected were FME, unexpected half scrams, and Riley temperature switches. For FME issues, the licensee had generated two adverse trend DERs, for unexpected half scrams, the team noted eight Unit 1 DERs associated with unexpected half scrams within the last year. Discussions with the Unit 1 system engineering staff indicated that the causes of the half scrams were generally unrelated that no adverse trend could be established. Based on the discussion with system engineering and a review of applicable DERs the team found the licensee's conclusion acceptable.

With respect to Riley temperature switches, the team noted eight DERs related to Riley Temperature switch failure at Unit 2 over the last three years. Discussion with members of the Unit 2 Instrumentation and Controls (I&C) Department and a review of the applicable DERs indicated that the trend associated with the temperature switch failures was being addressed. Although some minor implementation issues were noted, the team considered the licensee's evaluation of the issue as provided in DERs 2-97-0498 and 2-97-1560 to be technically sound. The licensee classified these DERs as category 2, but the team considered the potential for the problem to be a common failure made them more suitable to be classified as category 1.

Based on the teams review, the licensee, appears to identify and evaluate adverse trend conditions. However, during the review of these and other DERs, the team noted a not all DERs associated with adverse trends were included in the quarterly DER Program Summary Report, this observation was described in Section O7.3, "Deviation/Event Report Program Summary Trend Report."

c. <u>Conclusions</u>

Although no procedural guidance was provided for reporting adverse trends, the licensee appeared to be identifying and evaluating adverse trend conditions. Based on the team's review of the procedural noncompliance-related adverse trend DERs, the team considered the corrective actions taken to address human performance issues to be narrowly focused and not completely effective as evidenced by the

significant number of adverse trend DERs associated with procedural noncompliance issues.

O7.7 Independent Safety Engineering Group (ISEG)

a. Inspection Scope

Technical Specification 6.2.3 defines the function, composition, and responsibility of ISEG. This technical specification is only applicable to Unit 2. The technical specification states in part that ISEG shall function to examine unit operating characteristics, NRC issuances, industry advisories, license event reports and other sources of operating experience and make detailed recommendations for improving unit safety to the Vice President - Nuclear Safety Assessment and Support. The team evaluated ISEG's performance in carrying out these responsibilities.

The team interviewed the ISEG Director, ISEG members, and personnel from the plant staff to assess ISEG's performance in carrying out its responsibilities. The team also reviewed ISEG activity reports for the last twelve months and the two most recent self assessments prepared by the ISEG Director.

b. Findings and Observations

Overall, the team found that ISEG was functioning adequately to carry out its responsibilities as defined in Technical Specification 6.2.3. The team noted improvement over the last several months in ISEG's use of industry operating experience and NRC issuances for assessment planning. In the past, ISEG was more focused on providing follow-up assessments to site specific events rather than taking a more proactive approach utilizing industry operating experience. ISEG has also recently begun to perform broader range programmatic assessments rather than focussing on isolated issues and events. These are both positive trends that need to continue for ISEG to have a greater impact on improving safety.

The self assessments prepared by the ISEG Director identified areas for improvement that have not been followed through on. A self assessment recommendation was made in June 1996 and again in December 1996 for ISEG to perform team assessments on a pre-planned list of topics to provide broader oversights of functional areas including Operations, Engineering, Maintenance, and Technical Support. The team found no evidence that this recommendation had been implemented. Additionally, the December 1996 self assessment repeated the assessment results and program enhancements made in the previous self assessment completed in June 1996.

One of the ISEG responsibilities listed in the Technical Specifications is to examine unit operating characteristics. ISEG currently carries out this function through daily reviews of operating logs and plant parameters. There was no evidence of ISEG performing, or being provided with, any long term trends of unit operating characteristics to allow for a more thorough review and assessment of safety significant parameters.

c. Conclusions

Overall, ISEG was functioning adequately to carry out its responsibilities as defined in Technical Specifications. Although ISEG had performed self assessments and identified areas for improvement, follow through on the recommendations for improvement has been limited.

O7.8 Self Assessment Program

a. Inspection Scope

The team reviewed the licensee's self-assessment (SA) program including procedures, interviewed licensee personnel and evaluated selected self assessments from engineering, operations, and maintenance.

b. Observations and Findings

Administrative procedure NIP-ECA-05, "Self-Assessment," Revision 00, provided adequate guidance for the self assessment program. A sample of SA reports were reviewed and it was determined that the level of detail with respect to identifying performance weaknesses and planned or implemented corrective actions varied greatly between reports. Specific SA weaknesses included: (1) SAs which lacked specific criterion against which performance was judged, (2) Some SAs were essentially a summary of documents reviewed (e.g., tabulation of DERs, NRC reports, and QA assessments), (3) Some branches do not have a method for capturing routine performance observations for inclusion in the SA programs, and (4) Some SAs either lacked specific recommendations or did not provide a mechanism to formally track what was being done with recommendations. In addition, management expectations with respect to developing a two-year schedule of branch SAs, maintaining the timeliness of SAs (i.e., at least one within a six month period), and including a section within the SAs which assesses the adequacy of past corrective actions, have not been met by various branch organizations.

c. Conclusions

Overall the licensee had an adequate program for self-assessment activities. However, several weaknesses with the program implementation limit the effectiveness of the overall SA program, and may lead to missed opportunities to implement useful recommendations in a timely manner.

O7.9 Corrective Action Program Related to Human Performance

a. Inspection Scope

The team reviewed aspects of the licensee's corrective action programs and conducted personnel interviews to determine if the licensee's programs were adequately identifying and addressing human performance issues.

b. Findings and Observations

The primary method for identifying, tracking and dispositioning human performance issues is through the DER process. DER data is tabulated quarterly by the Quality Assurance (QA) department and provided as a report to each branch for further evaluation and corrective action. The team reviewed the QA DER Program Trend Summary Report for the second quarter of 1997 and a QA report to the Senior Management Team which characterized the 1997 significant DERS attributed to personnel errors, dated August 8, 1997, to determine what performance weaknesses were being identified. The licensee reports indicated that significant contributors to performance weaknesses appear to be concentrated in the areas of self-checking, required verifications not performed, and procedures not followed correctly. Results of these performance weaknesses have manifested themselves as plant equipment found out of expected position, work performed on plant equipment using inappropriate materials or equipment, and inadequate operability determination calculations.

In response to the human performance issues identified in the DERs, the licensee often counseled the individuals involved in the event and made changes to administrative or plant procedures. While these actions appear to be effective in minimizing the possibility of a repeat of a particular incident, the continued observation of personnel errors is indicative of the need to evaluate the underlying causes of these errors more broadly.

The team also reviewed a sample of DERs, recent RCAs, self-assessments, and various branch performance observation forms to determine if human performance issues were being identified. In most cases, these reporting methods did identify human performance issues contributing to events, but the team did note some exceptions. In at least one case, the licensee identified a lack of human performance contributors as a result of a DER review and initiated a second DER to address the human performance issues. A recent Quality Assurance Branch assessment of significant personnel errors noted that recent root cause analyses do not adequately evaluate the contribution of human performance to the events being analyzed, and DER C-97-1538 was written to address the issue.

The team noted some positive initiatives such as the Unit 2 Operations observation card system which contain performance observations generated by operations supervision of their respective crews. The observations are entered into a database which can be sorted on a variety of evaluation criteria and used as input into the self-assessment process. However, the team noted that some other branches did not have any method for capturing performance observations and in some cases, other branches had apparently stopped using existing observation processes contrary to management expectations.

The licensee appears to recognize that human performance weaknesses persist and has implemented initiatives to address the situations including: delineating management expectations for error free performance, increased supervisory

oversight of activities, increased emphasis on peer-checking, and performance reinforcement during training.

c. Conclusions

Overall, the licensee had an adequate program for identifying human performance errors. However several weaknesses in the programs to identify and address human performance issues were apparent.

O8 Miscellaneous Operating Issues

O8.1 Unresolved Item 50-410/95-25-03: DERs Extended Without Justification

a. Inspection Scope

During NRC Inspection 50-410/95-25 NRC inspectors identified examples of Unit 2 DERs assigned to both engineering and technical support departments that failed to contain justification for the extension of implementation as required by Procedure NIP-ECA-01. Additionally, the inspectors noted that documentation of extension requests varied widely. The team reviewed the licensee's actions taken in response to this concern, including the DER written to address the issue, a QA surveillance performed by the licensee to determine the extent of the problem, and resulting changes made to the DER procedure. The team also reviewed selected DERs to assess the effectiveness of the licensee's corrective actions to remedy the problem.

b. Findings and Observations

NMPC generated DER 2-96-0211 to address the concern related to DER extensions. As part of the disposition, QA completed a surveillance of the justifications provided for DER extensions. The results of the QA surveillance (Report 96-0039-C) identified that the only group to consistently justify DER extensions was Unit 1 Engineering Department. The licensee identified the root cause to be ineffective change management for Revision 8 to NIP-ECA-01, which incorporated the requirement for justifying DER extensions. Corrective actions included informing all branch managers through a memorandum of the requirements to justify DER extensions, and training on DER extensions was to be included for "DER coordinator" training. In addition, the DER procedure was enhanced to clarify the requirements for justifying and documenting DER extensions.

The team reviewed the licensee's corrective actions. The team considered that the procedure changes facilitate the use of DER extension requests. The team considered this enhancement to be good, and the DER extension requests reviewed by the team consistently used the extension forms and assessed the impact on safety. Although the procedure changes were considered to be good, the process was not consistently being used. There were currently 687 DERs open for disposition with 165 greater than ten days overdue without an extension request (51 were greater than 50 days overdue, and 16 were greater than 100 days overdue). With respect to implementation of the DER corrective actions, 1622

DERs were open with 72 DERs greater than ten days overdue without an extension request (29 were greater than 50 days overdue, and five were greater than 100 days overdue). The failure to justify the extension of DER disposition and implementation due dates was not in compliance with licensee Procedure NIP-ECA-01, and was considered a violation of TS 6.8.1. (VIO 50-220/97-80-01 and 50-410/97-80-01) Furthermore, based on the numbers DERs currently overdue without justification, the team considered the licensee's actions described in DER 2-96-0211 ineffective to prevent recurrence. Based on this violation, Unresolved Item (URI) 50-410/95-25-03 is closed.

c. Conclusions

The continuing failure to justify the extension of DER due dates as required by licensee procedure was a violation of TS 6.8.1. Furthermore, the licensee's corrective actions to prevent recurrence of this previously identified concern were ineffective.

O8.2 (Closed) Inspector Follow Item 50-410/96-07-12: Weaknesses in the DER Process

This item was opened in response to a finding during the 1996 Integrated Performance Assessment Process (IPAP) team inspection (NRC IR 50-220/96-201 and 50-410/96-201), in which weaknesses were identified within the DER process. The particular concerns were in the areas of trending, root cause analysis, adequacy of corrective actions to prevent recurrence, and root cause analysis training. Also, the implementation of corrective actions associated with self-assessments, ISEG, and QA recommendations were not verified sufficiently to assure that the required actions were effective.

During the course of this inspection, the team assessed all the areas of concerns identified within this Inspector Follow Item (IFI). The team's assessments were included in the applicable sections of this inspection report, and any continuing weaknesses requiring follow up were noted as such. In addition, subsequent to issuing IFI 96-07-12, Notice of Violations (NOVs) associated with the corrective action program were issued, as described in Escalated Enforcement Letter dated April 10, 1997; any continuing weaknesses pertaining to the corrective action program will be review as part of the NOV closures. Therefore, IFI 96-07-12 is administratively closed.

O8.3 (Closed) Inspector Followup Item (IFI) 50-410/96-07-13: ISEG Review of NRC Documents

The May 1996 IPAP report noted that ISEG was not carrying out its responsibility to review NRC issuances. This function was being performed by different branches other than ISEG. ISEG has taken actions to correct this situation and the team reviewed ISEG's functions with respect to this issue. A member of ISEG routinely reviews a complete listing of NRC issuances for applicability and safety significance. Selected items are flagged for a follow-up assessment by ISEG to determine if the issue is being properly addressed. The team reviewed ISEG activity reports for the

last twelve months and found evidence of these actions being taken and that meaningful feedback was being supplied by ISEG to responsible plant organizations.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Emergent Maintenance

a. Inspection Scope

The inspector observed various aspects of the licensee's response to emergent conditions that required corrective maintenance.

b. Findings and Observations

Unit 2 Reactor Coolant System Flexible Hose Failure

On August 4, 1997 Unit 2 was shutdown in response to an elevated drywell floor drain leak rate. The source of the leakage was a 3/4 inch flexible metallic hose, 2RCS*HOSE40, connected to the drain line of the B recirculation loop flow control valve, 2RCS*HYV17B. The leak was at the bottom of the flexible hose where the stainless steel braid is connected to the end ferrule. The team followed the licensee's response to the event as it related to implementation of the plant's corrective action program.

This was the second occurrence of a failed flex hose at Unit 2. On March 30, 1991 a flexible hose of similar design in the reactor coolant sample system failed, also resulting in a plant shut down. In response to the previous event, the licensee sent the failed flex hose off site for failure analysis. The cause of the failure was determined to be pitting attack and subsequent fatigue failure as a result of exposure to an aggressive environment prior to the hose being placed in service. The source and characterization of the aggressive environment were never established. The Licensee Event Report (LER) 91-01 submitted in response to this event committed to evaluating flex hoses removed in future outages for signs of metal fatigue. Only one of twelve flex hoses removed in the next refueling outage was subsequently examined. No evidence of metal fatigue was found in the sole flex hose that was examined. The team does not consider the examination of only one additional flex hose to have met the intent of the LER commitment to determine the extent of the failure mechanism. The team determined that the licensee did not have a sufficient enough understanding of the failure mechanism and contributing environment for the flex hose that failed in March 1991 to consider the failure to be an isolated event with no generic implications as stated in the LER.

The team assessed the licensee's response to the most recent flex hose failure. The team observed meetings of the root cause evaluation team, routine outage planning meetings, SORC meetings, interviewed personnel involved with responding

to the event, and walked down the location of the failed flex hose in the dry well. The team found the licensee's response to the event to be appropriate. The licensee removed the failed flex hose from the valve body and capped and seal welded the connections. Visual inspections were conducted on the remaining flex hoses. The licensee recognized the limitations of the visual inspections at identifying fatigued hoses prior to failure and made an appropriate safety assessment justifying plant restart.

The licensee's preventive actions for the most recent flex hose failure include prioritizing a list of flex hoses most susceptible to failure; identifying flex hoses for replacement, modification, or inspection in the next scheduled refueling outage; and performing a failure analysis on the failed flex hose and other selected flex hoses to establish a failure mechanism. The team considered the March 30, 1991 event a missed opportunity for the licensee to pursue the cause of the failed flex hose and establish appropriate corrective actions to prevent recurrence. The licensee considered several preventive actions in response to the March 1991 flex hose failure, but did not follow through on them. An inspector follow item, 50-410/97-06-02, was established to track the resolution of the most recent event.

Failure of Unit 2 Service Water Makeup Control Valve to the Circulating Water System

On August 18, while conducting activities involving the service water (SW) system, an operator noted that the hydraulic positioning unit for the SW loop B makeup control valve to the cooling tower was malfunctioning. Specifically, the hydraulic pump was running continuously; normally, it operates only as necessary to support valve operations and to maintain an accumulator full. The accumulator serves as a backup power source to the hydraulic pump, to allow the valve to isolate the non safety-related cooling tower from the safety related portions of the SW system. Continuous pump operation with no corresponding valve operations indicated that the accumulator was not holding pressure, and therefore could not be relied on to perform its safety function. As a result, SW loop B was declared inoperable, which placed the Unit 2 in a 72 hour shutdown action statement.

Due to the malfunction, switching SW loops for makeup to the cooling tower by the existing procedure would have temporarily resulted in two loops of SW being inoperable. To avoid this, a one-time use procedure change was prepared. The inspector observed preparations in the control room to perform this procedure. Following individual review of the change, operators discussed problems that could be encountered during the shift. Based on the sequence of procedural actions, parameters were established that would give early indications of a problem, as well as actions to be taken if problems did develop. However, due to the lateness of the shift and other required activities, the decision was made to defer conduct of the operation to the oncoming shift.

Based on turnover discussions of the procedure, the oncoming operations shift discussed the evolution in overview during the turnover brief. The pre-job brief was deferred until after completion of normal shiftly rounds and to allow the control

room operators to thoroughly review the procedure change. The inspector observed the shift turnover brief and noted that the auxiliary operators were active and knowledgeable participants in discussion of the upcoming SW evolution.

Unit 2 Emergency Diesel Generator DC Control Power Annunciator Failure

On August 18, operators received an alarm on main control board annunciator 319, "EDG2 DC Control Power Failure." Loss of DC control power for an emergency diesel generator (EDG) renders that EDG inoperable. Loss of EDG2 at that time would have been particularly significant, in that scheduled LCO maintenance on division 1 equipment was in progress. An operator was dispatched to investigate the condition and, from local indications, it was determined that the EDG2 DC control power was still operable. As an interim measure, an individual was stationed to monitor local indications while maintaining communication with the control room. Troubleshooting revealed that the cause of the alarm was a failed relay in the annunciator circuit. The relay was replaced and the annunciator was returned to service later the same day.

The inspector observed activities associated with the annunciator circuit relay replacement from the control room. The maintenance activity was thoroughly discussed, including expected alarms, prior to commencing work. Post maintenance testing was technically appropriate and was well controlled. Following restoration of the annunciator circuit and approval by the operations supervisor, the local watch was secured. The inspector concluded that use of a watchstander for this function had been acceptable, given that the affected circuit provided no functions other than alarm.

c. Conclusions

The licensee effectively dealt with these emergent maintenance issues. The operations department made significant contributions both to the identification of problems and control of plant conditions to support maintenance. An IFI concerning the failed flex hose was documented in a separate NRC inspection report 50-410/97-06-02.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition Observations

a. Inspection Scope

The inspector toured portions of the plants to assess the effectiveness of the corrective action process with respect to identifying and correcting material discrepancies.

b. Findings and Observations

Unit 2 Material Condition

During the first week of onsite inspection (August 4), unit 2 was shut down due to a reactor coolant leak from a flexible hose in the drywell. As a result, the inspectors were able to tour areas that are normally inaccessible during power operations.

Drywell

The main steam isolation valves appeared to be in good material condition; nitrogen flexible hoses were not crimped and actuator venting was not obstructed. No problems were noted with the mounting of piping and electrical conduit runs, nor with seismic restraints. No temporary storage of equipment or materials was noted, and no temporary postings were observed. Drywell coatings appeared to be in good condition, and no peeling was noted. Overall, the inspectors considered that the material condition of the drywell was good; drywell cleanliness is discussed in section M2.2 below.

Steam Tunnel

The inspectors noted several previously unidentified deficiencies that had occurred during the preceding plant operations. For example, a valve packing leak had developed which created a puddle of water on top of one of the room coolers. Also, a flange leak on a steam pipe had melted the surrounding insulation. In addition, the inspectors noted several maintenance-related material deficiencies. Examples included: the inlet screens/filters were not in place on one of the room coolers; one of four baseplate fasteners was not made up for a seismic strut; frayed, crumpled fire wrap material; and a long ladder that was being stored upright without adequate restraint. Overall, the inspectors assessed the material condition of the steam tunnel to be poor.

A-Feedwater Heater Bay

No significant problems were noted, overall material condition and housekeeping appeared to be good.

Unit 2 Reactor Building

The inspectors also toured the reactor building during the course of the inspection, and made the following observations:

Control rod drive system relief valve 2RDS*RV1B (RDS pump 1B suction relief) had an open threaded port on the valve bonnet; the inspector noted that this port for the 1A RDS pump suction relief valve was plugged and lockwired. The licensee initiated a DER (2-97-2455) to investigate this inconsistency. The licensee determined that the plug was supposed to be installed, but that it did not affect

valve operability; the bonnet is vented to the valve discharge side by an internal passage, and the valve relieves to atmospheric pressure. A plug was promptly installed in 2RDS*RV1B.

Gas treatment system valve GTS-PV104 (AOV-101 bypass line pressure controller) position switch actuator on the valve stem was rotated so that it was out of alignment and made minimal contact with the limit switches. The licensee initiated a problem identification report to correct the problem.

The discharge flexible coupling for reactor building closed loop cooling pump CCP-P1A had several radial tears in the outer covering. As compared to the other pumps in the system, the coupling appeared to be slightly deformed, suggesting that the cause of the tears was an inadequate fit. Although a work order existed to replace this flexible coupling, the reason for the work order was listed as preventive maintenance, indicating that the tears apparently had not been previously identified.

c. Conclusions

The overall material condition of Unit 2 was good; however, inspector identification of several material problems in the reactor building indicated that additional material inspections by the licensee could be productive. The material condition of the steam tunnel was assessed to be poor. Based on the material deficiencies that were identified by the inspectors in this area, it did not appear that the licensee was taking full advantage of the forced outage to inspect normally inaccessible areas of the plant for emergent material problems.

M2.2 Unit 2 Drywell Cleanliness Controls

a. Inspection Scope

During an inspection of the Unit 2 drywell, the inspectors identified some foreign materials in out-of-the-way locations. As a result, the inspectors reviewed the licensee's cleanliness control requirements for the drywell.

b. Findings and Observations

The Unit 2 drywell was opened during the forced outage to support repair of the failed reactor coolant system flexible hose, but was not open for general access. In discussions with plant personnel during entry preparations, the inspectors were informed that the drywell was a level 3 cleanliness area, and that foreign material exclusion (FME) requirements were in effect. The general standard for area cleanliness requirements is ANSI N45.2.3, "Housekeeping During the Construction Phase of Nuclear Power Plants," and the requirements for level 3 cleanliness as specified in this ANSI standard are relatively stringent. Area cleanliness classifications for Unit 2 are established by procedure GAP-HSC-02, "Local Work Zones and System Cleanliness Controls," and basically parallel the requirements of ANSI N45.2.3.

During inspection of drywell, the inspectors noted that the overall cleanliness of the drywell was good. However, the inspectors observed that numerous open-ended square steel structural braces were collecting points for debris (for example, tie wraps, wire, and contamination swipes), as well as some tools (the inspectors found two pens and two screwdrivers). The inspectors considered that these conditions were not consistent with level 3 cleanliness requirements. However, in reviewing GAP-HSC-02, the inspector noted that the cleanliness level of the drywell was not specified. The procedure does discuss the use of FME controls (material accountability log and capturing of loose items) for the drywell; since FME controls are normally established for systems requiring a high degree of cleanliness (level 1, 2, or 3), this could imply that the drywell was a level 3 area. However, in this case, the use of FME controls is to maintain drywell cleanliness at the level established during the previous closeout inspection and thereby preclude the need for a drywell closeout inspection following a short duration outage.

In addition, the inspector was informed that heavy fabric cleanliness covers were used to maintain FME control of the drywell-to-suppression pool downcomers. While this is an effective mechanism for maintaining cleanliness, the inspector was concerned that, were they to be inadvertently left in place while primary containment was required, they would have a significant effect on the ability of the containment to perform its design functions; specifically, while in place, they defeated the steam quenching function of the suppression pool, and if dislodged, could produce significant blockage of water to the ECCS pumps. The inspector was informed that the downcomer covers were used as deemed necessary by the drywell coordinator, and that installation and removal was documented by the material accountability log. The inspector considered that more stringent controls over installation and removal of these covers would be appropriate, due to the major impact they could have on containment operability.

The requirement to perform a drywell closeout inspection prior to plant startup is established by procedure N2-OP-101A, "Plant Startup." As a prerequisite to the procedure, either the master or short form startup checklist (Attachments 1 and 2) must be completed, and both require that a drywell inspection be performed if a drywell entry had been made. However, GAP-HSC-02 specifies that, for short outages, FME controls may be used in lieu of a final inspection. It was not clear how this provision is intended to be implemented. The inspector was concerned, because the N2-OP-101A drywell closeout checklist is the source of the requirement for final verification that the downcomer covers have been removed; were it to be interpreted as not being required, then this final verification would not be performed.

The inspector noted that GAP-HSC-02 specifies that installation and removal of the downcomer covers is to be performed under work order control. The inspector considered this to be an appropriate level of administrative control for use of the downcomer covers. The inspector verified that a work order (97-00852-03) had been used to control use of the downcomer covers during the August 4 forced outage; however, it was a general work order for drywell FME control, titled, "FME Control Accountability of Material in the Drywell During Forced Outage," rather than

a work order specifically for the installation and removal of downcomer FME covers. Additionally, the work order did not specify which downcomers were to be covered, but rather, had blanks for the worker to record the identification numbers of the affected downcomers. The inspector noted that the completed work permit did not provide rigorous accountability for placement of the covers. For example, removal of four covers was documented by having lined out the numbers that had been recorded in the "installation" section, with a note that they were removed and reinstalled at the locations listed on the next line; this removal had not been recorded in the "removal" section of the work permit. In the same example, one of the downcomers listed as having its cover removed is also listed on the next line as having a cover installed. Finally, in the "removal" section, it would not be possible to determine whether one of the numbers was "6" or "8" (due to a write-over) without referring to the "installation" section to find out which it should be.

c. Conclusions

Drywell cleanliness was generally good, however, cleanliness requirements for the drywell are not clearly established in the governing procedure, GAP-HSC-02. Given that this procedure provides allowance for not performing a drywell inspection prior to plant startup, and that the plant startup procedure, N2-OP-101A, does not address how this allowance is to be implemented, interpretation could result in omission of the final verification that the downcomer FME covers have been removed. Work order control of installation and removal of the downcomer FME covers is appropriate, given the significant impact they could have on containment operability if inadvertently left in place. However, the work order used to accomplish this during the August 4 forced outage was general in nature and did not provide rigorous accountability for installation and removal of these covers.

M2.3 Unit 2 Residual Heat Removal System Flow Control Valve Problem

a. Inspection Scope

The inspector noted a mechanical problem with a residual heat removal (RHR) system valve, and observed the licensee's actions to disposition the deficiency.

b. Findings and Observations

During an inspection of the Unit 2 reactor building, the inspector noted that a split ring lock washer between a nut and the anti-rotation device on the stem of valve RHS*FV38B ("B" RHR full flow test) was not compressed. The inspector reported this condition to the station shift supervisor (SSS) late in the afternoon of August 18. Licensee investigation of the condition the following day identified the valve as having a two piece stem, and that the nut and lock washer in question were the mechanical fasteners that locked the two threaded stem pieces together. The condition of the valve was assessed to be indeterminate. At 11:00 a.m. on August 19, the valve was declared inoperable, along with the associated loop of the RHR system. This placed the licensee in a 72-hour shutdown action statement per

technical specification 3.6.2.3. DER 2-97-2451 was initiated to document the condition in the corrective action program and initiate corrective action.

The condition of valve RHS*FV38B was evaluated by an engineering supporting analysis (ESB2M970760). The analysis indicated that the functions of the valve included initiating and terminating suppression pool cooling during normal plant operations and accident conditions, and as an RHR pump minimum flow valve operated from the remote shutdown panel in case of control room evacuation due to fire. The evaluation concluded that the valve position was currently known, but that, with continued operation, the lower stem could loosen and back out of its connection with the upper stem, resulting in inability to open the valve.

Licensee review revealed that there had been a problem had with valve RHS*FV38B in June 1997. Specifically, the valve position indication had been intermediate when the valve was fully closed. This condition was corrected with a minor adjustment of the valve position limit switch. At the time, the problem was believed to be due to the switch having been set too close to the maximum closed tolerance. However, in light of the loose lock nut, it was considered likely that the intermediate position indication had been due to increased stem length, as a result of the lower stem beginning to back out of the upper stem.

Repair of valve RHS*FV38B was performed under work order 97-12724-00, and consisted of tightening the loose nut. Acceptance testing was to stroke time the valve and verify proper valve position indication. During this testing, the valve again exhibited dual indication, indicating that the stem had continued to back out since June. The problem was again corrected by minor adjustment of the valve position limit switch, and valve stroke time was demonstrated to be satisfactory. Valve RHS*FV38B and RHR system loop B were declared operable on August 20. Additionally, the licensee verified that similarly designed valves in safety systems did not exhibit the same problem.

c. <u>Conclusions</u>

Given the safety significant functions performed by valve RHS*FV38B, licensee investigation of the reported degraded condition of the valve was slow. Additionally, the decision to start the 72 hr LCO at 11:00 a.m. on August 19, rather than on the afternoon of August 18 (when the condition was reported to the SSS) was not conservative. The intermediate valve position indication that occurred in June 1997 was apparently a missed opportunity to identify the loose stem lock nut. Pending engineering evaluation of the as-left, partially unthreaded condition of the lower valve stem and review of the completed DER, this item remains open. **(IFI 50-410/97-80-02)**

M2.4 Unit 2 Steam Tunnel Door Seal

a. Inspection Scope

The inspectors reviewed the adequacy of a temporary modification of the Unit 2 steam tunnel door seal that was in place from 1992 to 1996.

b. Findings and Observations

The entrance to the Unit 2 steam tunnel consists of two doors, separated by a short passage way. The outer door is a single latch security door, and the inner door is a multiple latched metal door with an elastomer seal around the edge; together, the doors form a portion of the secondary containment boundary. During an inspection of the steam tunnel, the inspectors noted a puddle of sticky liquid on the floor of the passage way between the two doors. The licensee determined that the material was elastomer door seal material. The inner door seal had been replaced during the 1996 refueling outage; some of the old seal material had been inadvertently left in the passage way and had decomposed. The inspector was concerned that the elastomer might not be appropriate for use as a steam tunnel door seal.

The inspector determined that a DER (2-96-0836) had been written on March 29, 1996 concerning degradation of the inner steam tunnel door seal. The DER indicated that the door seal was melting, that there were puddles of seal material on the floor, and that air was bubbling through the seal area. The problem had previously been documented in a problem identification report (11716) on February 18, 1996. The DER also indicated that the problem had happened before and that the seal had last been replaced in March 1992.

The resolution to DER 2-96-0836 provided a history of problems with the inner steam tunnel door seal. Melting of the seal was first noted in 1991 and documented in DER 2-91-Q-0755. The condition was evaluated as being due to use of an incompatible cleaning solvent. Corrective action was to replace the existing neoprene seal with an urethane seal. This was performed as a temporary modification (91-068) in 1992. The urethane seal had a five year life, but a design temperature of only 90 degrees Fahrenheit (°F); the actual environmental temperature can be as high as 130°F. As a result, the seal was deteriorating (melting) after four years of service. DER 2-96-0836 concluded that the door was operable in its degraded condition, because it was still able to hold a seal. The root cause of the door seal degradation was an inadequate design evaluation of the urethane seal material for environmental conditions. The cause of the inadequate design evaluation was indeterminate.

As corrective action, an engineering design change (2F00373A) was developed to replace the urethane seal with a more suitable material. An interim corrective action, to install a new seal of the same material during a forced outage, was never performed because there were no forced outages prior to shutdown for refueling. The design change was implemented during the 1996 refueling outage, and installed a seal composed of E401 EPDM compound.

One of the functions of the inner steam tunnel door is to act as a portion of the secondary containment boundary. Per technical specification 3/4.6.5.1, secondary containment integrity is demonstrated by the ability to maintain at least 0.25 inches of vacuum (water gauge) within the secondary containment; there are no requirements for leak tightness of individual boundaries. Given that the required vacuum was maintained from the time the degraded condition was identified until the plant was shutdown for refueling outage, the inspector concluded that the inner steam tunnel door seal was adequate to perform its secondary containment function, even though it was progressively degrading.

DER 2-96-0836 states that the inner steam tunnel door is also a class C (three hour) fire door. The DER indicates that engineering determined that the urethane seal does not sustain a fire and is a proper door material to have in a fire boundary to maintain a three hour fire rating. The inspector was concerned that this determination suggested that there was a requirement for the seal to function as a portion of the fire barrier. However, in discussions on this matter, the licensee indicated that the seal served no fire protection function, and that the recess for the seal formed a baffle which directed fire away from the gap between the door and the frame. Therefore, the inspector concluded that the fire protection function of the door had not been degraded by the inadequate door seal.

c. Conclusions

The temporary modification that installed a urethane seal on the inner steam tunnel door in 1992 was inadequate, in that it failed to account for environmental temperatures that exceeded the design temperature of the seal material. After seal degradation was identified, corrective actions were appropriate. Use of the inappropriate seal material from 1992 until 1996 had the potential to cause a failure of secondary containment; however this did not occur, and the degraded condition did not constitute a violation of any other specific regulatory requirements. Operability of the door as a fire barrier was not affected by the degraded seal.

M3 Maintenance Procedures and Documentation

M3.1 Problem Identification and Work Control Process

a. Inspection Scope

Applicable work control procedures were reviewed to determine the effectiveness of problem identification processes.

b. Findings and Observations

Procedure GAP-PSH-01, "Work Control" establishes the procedure for entering equipment/material problems into the corrective action program. Problems are entered into the program by the identifying individual using a problem identification (PID) report. PIDs that involve plant equipment or operations are initially reviewed

by the SSS for operability/reportability. A PID ultimately causes a work order to be generated to correct the identified problem.

In reviewing GAP-PSH-01, the inspector noted that it did not provide guidance concerning equipment problems that should also be reported under the DER system. On the other hand, procedure NIP-EAC-01, "Deviation/Event Report," does refer to the use of PIDs in parallel with DERs. The inspector considered that material problems identified by a PID might not receive the same level of management attention and evaluation (for example, root cause evaluation) as if a DER had been used. Also, the inspector noted that newly submitted PIDs are reviewed by the SSS every 24 hours. The inspector considered that this could delay operability issues from being recognized, although no instances of this were noted. Finally, the inspector noted that GAP-PSH-01 discusses the use of deficiency tags, however none were observed to be posted during plant tours. The licensee acknowledged the inspector's observations but indicated that the approach of using the computer data base to enter and track PIDs in lieu of using deficiency tags meets management expectations.

c. <u>Conclusions</u>

The problem identification system procedures established adequate guidance for work control. However, the PID process does not procedurally ensure the same level of review and evaluation as does the DER entry mechanism for the corrective action program.

M3.2 Operator Work Arounds

a. <u>Inspection Scope</u>

The inspector reviewed licensee processes for identifying, tracking, and correcting operator work-around items.

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

The governing procedure for tracking control room deficiencies at Unit 1 is N1-ODG-04, "Control Room Deficiencies Guideline." The procedure establishes basic classifications of deficiencies, including corrective maintenance deficiencies, defeated annunciators, extended markups and holdouts, configuration control holdouts, longstanding control room operator aids, and invalid and nuisance alarms. The control room deficiency log is maintained by the shift technical advisor and is reviewed monthly by the operations manager. At the time of this inspection, the Unit 1 control room deficiency list contained 20 items.

Control room deficiencies at Unit 2 are tracked in accordance with N2-ODP-0001, "Conduct of Operations," section 3.3.8. Other than markups, control room deficiencies are documented by PIDs. At the time of this inspection, the Unit 2 control room deficiency list contained 35 items.

Operator work arounds at Unit 2 are tracked in accordance with procedure N2-ODI-5.70, "Work Arounds and Longstanding Tagouts." Items are identified as operator work arounds using a Work Around Tracking Form, and tagouts greater than six month old are designated as longstanding. Based on two year trending presented by the licensee, this procedure appears to be effective; work arounds have been reduced from about 40 in mid-1995 to 19 at the time of this inspection, and longstanding tagouts have been reduced from about 100 to about 30.

In reviewing the work around list, the inspector noted that some items that had been examined and were apparently resolved, were still being carried on the list. For example, the requirement for operators to open specific circuit breakers for some Appendix R fire scenarios was listed as a work around in January 1996. However, the issue was addressed in DER 2-94-0202, and as a result, the requirements have been incorporated into the appropriate procedures, and the FSAR has been updated to indicate this strategy. In another example, operator action to run emergency fans during the summer to maintain EDG room temperatures less than 95°F was added in July 1996. However, in discussions with system engineering, the inspector was informed that the emergency fans start automatically when the associated EDGs start, and that there were no room temperature issues that affected EDG operability; the identified work around was considered to be a habitability issue and no action was being taken to address it. The inspector considered that continuing to carry such item could lessen the credibility of the operator work around list.

The inspector reviewed the operator work around list for Unit 1 and noted that it included five items. From discussions with the coordinator of the operator work around list, the inspector determined that a procedure was being developed to incorporate enhancements such as prioritization of corrective actions. Improving the effectiveness of the operator work around list appeared to have significant management attention.

c. <u>Conclusions</u>

Adequate procedures and processes are in place for identification and correction of operator work arounds. Unit 2 has been effective in reducing the number of operator work arounds and longstanding tagouts. Some items being carried on the Unit 2 operator work around list apparently have no recourse remaining, and could lessen the credibility of this corrective action mechanism.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Unresolved Item 50-410/95-25-02: Extended Inoperability of the Unit 2 Loose Parts Monitor

a. <u>Background</u>

This item concerned the inoperability of the loose parts monitor (LPM) from July 1991 until it was noted by the NRC resident inspector in December 1995. As discussed in inspection report 50-410/95-25, the inspectors were concerned with the weak organizational attention that had allowed the LPM to be inoperable for so long. The licensee initiated DER 2-95-3455 to investigate this situation.

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

The inspector reviewed DER 2-95-3455, "Timeliness of restoration and reporting for LPM system inoperability." The DER indicated that the longstanding system inoperability was the result of repeated attempts to correct system lockups that occurred during plant operations at less than full power. The system lockups were due to alarms, caused by increased background noise, from the LPM channels that monitored the recirculation loops. The licensee addressed this hardware issue by transferring it to another DER, 2-95-2128, while DER 2-95-3455 went on to address additional reportability requirements and the lack of timely corrective action.

The root cause evaluation concluded that the cause of this event was managerial methods, based on the repetitive problems and that managements response to the problems were untimely and ineffective. However, the evaluation proposed no corrective actions. The root cause verification noted that the problem would not recur if the root cause was eliminated, because, "appropriate management oversight on long standing hardware issues will prevent similar occurrences in the future." However, the mechanism by which this is supposed to occur is not identified. The evaluation went on to indicate that a system engineer has been assigned to the LPM system, which the inspector considered to be a substantive measure to prevent recurrence.

The hardware problem with the LPM system was corrected by disabling the alarm function for the recirculation loop detectors (four of the 10 channels in the system). The technical acceptability of this approach is discussed in safety evaluation 96-089. The system modification was completed during the 1996 refueling outage and was reported to the NRC in a letter from the licensee, NMP2L 1678, dated December 6, 1996. As of this inspection, the LPM system remained operable.

c. <u>Conclusions</u>

The extended inoperability of the LPM system was due to ineffective management oversight of efforts to resolve a technical issue. The licensee's root cause evaluation did not specify corrective actions, and the mechanism by which increased management oversight will be maintained was not clear. However, given

that the longstanding hardware problems with the LPM system have been addressed and that the system has been returned to service, this item is closed.

M8.2 (Closed) Inspector Followup Items 50-220/96-07-17 and 50-410/96-07-17: Extended Installation Period for a Service Water System Temporary Modification

This item concerned temporary modification 91-107, which installed a corrosion monitoring station for the Unit 2 service water system. The modification consisted of rack mounted corrosion coupons which were used to assess the effectiveness of biocides at controlling microbiologically induced corrosion and biofouling. Per discussions with the licensee, the long installation period was required to develop and verify the long term effectiveness of what would become a permanent chemical treatment system. This temporary modification was subsequently incorporated as part of a permanent modification (design change N2-94-007) which installed the service water chemical treatment system. Design change N2-94-007 was completed on August 8, 1997, therefore, this item is closed.

III. ENGINEERING

E7 Quality Assurance in Engineering Activities

E7.1 50.59 Program Review

a. Inspection Scope

The team reviewed safety evaluations and applicability reviews prepared by the licensee in support of changes, tests, and experiments made in accordance with 10 CFR 50.59. The licensee uses applicability reviews for a preliminary screening to determine if 10 CFR 50.59 is applicable to the proposed change. The team measured the licensee's performance by the quality of the safety evaluations and applicability reviews.

The team reviewed the following safety evaluations prepared for each unit.

Unit 1	Unit 2
97-021, Draft E, Rev. 0	97-046, Draft C, Rev. 0
97-024, Draft C, Rev. 0	97-050, Draft A, Rev. 0
97-108, Draft A, Rev. 1	97-057, Draft A, Rev. 0
97-119, Draft A, Rev. 0	97-060, Draft A, Rev. 2
97-114, Draft B, Rev. 0	97-062, Draft A, Rev. 0
	97-070, Draft A, Rev. 0

In addition, the team reviewed 26 applicability reviews conducted at Unit 1 and 16 applicability reviews conducted at Unit 2. The team reviewed SORC and SRAB meeting minutes for the past six months to assess the management oversight of the 50.59 program and also interviewed qualified preparers of safety evaluations and applicability reviews.

b. Findings and Observations

The team found the quality of the safety evaluations to be good. The increased quality of the safety evaluations can be attributed, in part, to good senior management oversight of the program. The SORC and SRAB meeting minutes show evidence of detailed reviews of safety evaluations by senior management. Good feedback was provided to the preparers of safety evaluations.

The team found the quality of applicability reviews to be mixed. The applicability reviews prepared by individuals experienced in the 50.59 process were of good quality. Applicability reviews prepared by individuals less experienced in the 50.59 process were of lesser quality. The team had comments concerning the amount of detail provided in the description of the proposed change for 6 of the 26 Unit 1 applicability reviews and 6 of the 16 Unit 2 applicability reviews that were presented. In some cases the written responses provided for justification of the answers to the five screening questions were not of sufficient detail to support the preparer's conclusions. In no case did the team find the applicability review conclusion to be incorrect. The team noted that the licensee's procedures do not require supervisory approval of completed applicability reviews, and there was no evidence provided that any site organization conducted routine periodic reviews of completed applicability reviews for adherence to plant procedures.

c. Conclusions

The quality of safety evaluations were good and could be attributed in part to good senior management oversight of the program. In contrast to the quality of the safety evaluations, the quality of applicability reviews was mixed primarily due to the level of documentation. In some cases, documentation was not sufficient to support the conclusions.

E8 Miscellaneous Engineering Issues

E8.1 IFI 50-220 & 410/96-07-14: Weaknesses in the 50.59 Program

The May 1996 IPAP report noted that the quality of safety evaluations and applicability reviews prepared by plant personnel needed improvement. This comment was made in part based on the number of safety evaluations that were being rejected by the two management review committees.

Since the IPAP report was published, plant management has made a significant effort to improve the quality of safety evaluations. A review of recent SRAB and SORC meeting minutes indicate that the rejection rate is near zero and the committee members have continued to ask challenging questions of the preparers. The team independently reviewed the five most recent safety evaluations completed at both units and found the quality to be good.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on August 22, 1997. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedure and/or parameters.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Abbott, Unit 1 Plant Manager
D. Baker, Licensing Supervisor
C. Beckham, Manager, Quality Assurance
J. Burton, Director, ISEG
W. Connolly, QA Audit Supervisor
J. Conway, V.P. Nuclear Engineering
G. Corell, Mgr., Chemistry-U1
R. Dean, Manager, Unit 2 Engineering
A. DeGracia, Mgr., WC/Outage-U1
M. Dooley, Operations Support Unit 1
S. Doty, Maintenance Manager-U1
J. Dryfuss, General Supervisor Operations Support
T. Fiorenza, Technical Support
J. Forderkonz, Refueling Floor Coordinator Unit 1
D. Goodney, Electrical Engr. Supv.-U1
G. Gresock, Licensing Engineer
R. Hall, Director HRD
G. Helker, Unit 2 WC/OMG
B. Holloway, NMPC U1-Chemistry
K. Johnson, Engineer
A. Jolka, Supervisor, Unit 2 Electrical Engineering
M. Kalsi, Unit 2 Electrical Engineering
G. Kahn, ISEG-U2
D. Lundeen, Maintenance Support Unit 1
J. Mancuso, Operations Support
P. Mazzaferro, Mgr., Tech Support-U1
R. McCoy, Operations Support Unit 1
B. Murtha, Operations Manager Unit 1
D. Pike, Project Management Unit 1
M. Pisano, Maintenance Manager, Unit 2
N. Rademacher, Executive Staff
A. Raju, Unit 2 Electrical Engineering
B. Smith, Operations Manager Unit 1
R. Strusinski, Operations Supervisor
J. Swenszhowski, Director, Q1P
K. Sweet, Unit 1 Technical Support Manager
R. Sylvia, NMPC Exec. V.P.
R. Tessier, Training Manager
C. Terry, Vice President NSAS
A. Vierling, General Supervisor, Fuel and Analysis
C. Wave, Chemistry Manager
G. Whitaker, Engineer, ISEG
B. Wolken, Maintenance-U2
D. Wolniak, Manager of Licensing

NRC

T. Beltz, Resident Inspector
L. Doerflein, Chief, Reactor Projects Branch 1
B. Norris, Senior Resident Inspector

INSPECTION PROCEDURES USED

40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-220 & 410/97-80-01	VIO	Failure to Justify the Extension of DER Disposition
50-410/97-80-02	IFI	Engineering Evaluation and Corrective Actions Concerning Degraded "B" RHR Full Flow Test Valve

Closed

50-410/95-25-02	URI	Extended Inoperability of the Unit 2 Loose Parts Monitor
50-410/95-25-03	URI	DERs Extended Without Justification
50-220 & 410/96-07-12	IFI	Weaknesses in the DER Process
50-410/96-07-13	IFI	ISEG Review of NRC Documents
50-220 & 410/96-07-14	IFI	Weaknesses in the 50.59 Program
50-220 & 410/96-07-17	IFI	Extended Installation Period for a Service Water System Temporary Modification

Discussed

None

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
DER	Deviation/Event Report
EDG	Emergency Diesel Generator
ESA	Engineering Support Analysis
FME	Foreign Material Exclusion
I&C	Instrumentation and Controls
IFI	Inspector Followup Item
IN	Information Notice
IPAP	Integrated Performance Assessment Process
ISEG	Independent Safety Engineering Group
NMP	Nine Mile Point
NMPC	Niagara Mohawk Power Corporation
PID	Problem Identification
QA	Quality Assurance
RHR	Residual Heat Removal
SA	Self-Assessment
SIL	Service Information Letter
SSS	Station Shift Supervisor
SW	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
Unit 1	Nine Mile Point Unit 1
Unit 2	Nine Mile Point Unit 2