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Team Leader:	R. Gibbs, Senior Reactor Inspector Maintenance Branch Division of Reactor Safety
Inspectors:	W. Bearden, Reactor Inspector, Maintenance Branch, RII R. Gibbs, Resident Inspector, North Anna Site M. Miller, Reactor Inspector, Engineering Branch, RII J. Wilcox, Senior Operations Engineer, NRR P. Wilson, Senior Reactor Analyst, NRR
Accompanying Personnel:	K. Coyne, Reactor Analyst, NRR D. Ashley, Operations Specialists, NRR Angel L. Coello Ortega, CSN/Consejo de Seguridad Nuclear Spain Luis A. Gerez Martin, CSN/Consejo de Seguridad Nuclear Spain

Approved By: [signature] 11/24/97

Paul E. Fredrickson, Chief
Maintenance Branch
Division of Reactor Safety

Date Signed

EXECUTIVE SUMMARY

North Anna Nuclear Station
NRC Inspection Report 50-338,339/97-08

This inspection included a review of the licensee's implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" [the Maintenance Rule]. The report covered a one-week period of inspection.

Overall, the inspection team concluded that the licensee had made significant improvements in the Maintenance Rule program since the Surry inspection. However, additional effort is needed to correct significant deficiencies and weaknesses, observed by the team and identified in self-assessments, regarding the adequacy of the Probablistic Risk Assessment (PRA). NRC review of these problems was identified as an inspection followup item (IFI).

Engineering

- The licensee and the NRC identified significant problems in the North Anna PRA. Because of these problems the team could not determine the quality of Maintenance Rule implementation with regard to risk ranking, goal setting and performance criteria, and the adequacy of the licensee's risk assessment tools. The team was able to conclude that the plant was being safely operated in consideration of risk (Sections M1.2.b.2, M1.2.b.3, M1.2.b.4, and M1.5).

- The rigor and depth of discussions during the observed working group meeting were appropriate for the matters discussed (Section M1.2.b.5).

- The PRA knowledge of interviewed working group members was weak. Due to a lack of understanding of the North Anna PRA, the Maintenance Rule working group did not appear to be able to compensate for the PRA's limitations. A permanent PRA member was assigned to the working group during the inspection to correct this weakness (Section M1.2.b.5).

- The licensee had effectively implemented a comprehensive process for performing safety assessments for on-line maintenance activities (Section M1.5).

- Some Maintenance Rule functional equipment groups (FEGs) did not receive a risk informed assessment (Section M1.5).

- In general, system engineers' technical knowledge of their systems was sound. Recent reassignments contributed to a lack of system specific knowledge (Section E4.1).

- In general, system engineer's understanding of the Rule and its implementation were weak. The Virginia Power Maintenance Rule program was corporate driven with minimal reliance on the system engineers for implementation. This was different than most programs reviewed by the NRC (Section E4.1).

Maintenance

- Required structures, systems, and components (SSCs) were included within the scope of the Rule with the exception of two structures and several annunciators. Enforcement discretion was used regarding these deficiencies (Section M1.1).

- The licensee had not established condition monitoring performance criteria for several SSCs for which the performance criteria was zero failures (Section M1.2.b.4).

- The periodic evaluation performed by the licensee met the requirements of Section (a)(3) of the Rule (Section M1.3).

- The approach to balancing reliability and unavailability was reasonable (Section M1.4).

- Corrective action for failures was adequate, and reliability and unavailability data were being properly captured for the SSCs reviewed (Sections M1.6 and M1.7).

- One weakness concerning the logging of failures against the appropriate FEG for the high head safety injection system (HHSI) was identified (Section M1.6).

- One weakness concerning the appropriateness of the reliability performance criteria for the post accident hydrogen removal system was identified (Section M1.7).

- In general, industry wide operating experience was used (Section M1.6 and M1.7).

- The structures program established under the Rule was comprehensive, was effectively implemented, and was assessed as a strength (Section M1.7).

- In general, walkdown of SSCs determined that they were being appropriately maintained (Section M2.1).

- Self-assessments of the Maintenance Rule program were thorough and considered a programmatic strength. Corrective actions sampled by the team were appropriately implemented (Section M7.1).

- The licensee did not have a systematic approach for closing out items in self-assessments. This failure to track and follow-up on self-assessment items was an indicated weakness (Section M7.1).

Operations

- Licensed operators understood their specific duties and responsibilities for implementing the Maintenance Rule (Section 04.1).

- Licensed operators, shift technical advisors (STAs) and schedulers understanding of the risk assessment tools for removal of equipment from service was good (Section 04.1 and M1.5).

Report Details

Summary of Plant Status

Both North Anna units operated at power during the inspection period.

Introduction

The primary focus of this inspection was to verify that the licensee had implemented a maintenance monitoring program which met the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (the Maintenance Rule). The inspection was performed by a team of inspectors that included a team leader, two Region II inspectors, one resident inspector, one NRR senior reactor analyst, and one NRR senior operations engineer. In addition, NRC staff support was provided by the senior operations engineer from NRR. The licensee provided an overview presentation of the program to the team on the first day of the inspection. The overview handout is included as an Attachment to this report.

I. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Scope of Structures, Systems, and Components Included Within the Rule

a. Inspection Scope (62706)

Prior to the onsite inspection, the team reviewed the North Anna Updated Final Safety Analysis Report (UFSAR), licensee event reports, the emergency operating procedures (EOPs), previous NRC inspection reports, and information provided by the licensee. The team selected an independent sample of SSCs that the team believed should be included within the scope of the Rule, which was not classified as such by the licensee. During the onsite portion of the inspection, the team used this list to determine if the licensee had adequately identified the SSCs that should be included in the scope of the Rule in accordance with 10 CFR 50.65(b).

b. Observations and Findings

The licensee appointed an expert panel to perform several Maintenance Rule implementation functions including establishing the scope of the Maintenance Rule. The panel reviewed 114 systems and structures for Units 1 and 2 of which 97 were determined to be under the scope of the Rule. The results of the expert panel were documented in the North Anna Maintenance Rule Scoping and Performance Criteria Matrix. The version of the matrix used for the team's review had been approved by the North Anna working group on September 23, 1997.

The team reviewed the licensee's Maintenance Rule scoping matrix to verify that all required SSCs were included within the scope of the Maintenance Rule. The team's review was performed to assure the scoping process included:

- All safety-related SSCs that are relied upon to remain functional during and following design basis events and to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines

- Non-safety SSCs that are relied upon to mitigate accidents or transients

- Non-safety SSCs which are used in the plant EOPs

- Non-safety SSCs whose failure could prevent safety-related SSCs from fulfilling their safety-related function

- Non-safety SSCs whose failure could cause a reactor trip or actuation of a safety-related system.

The team reviewed the licensee's scoping matrix and verified that all required SSCs were included in the Rule with the exception of the following:

- The licensee had not included the switchyard control house and communications building in the scope of the Maintenance Rule. Review of components located in this structure determined that protective relays and other electrical power distribution equipment associated with the offsite electrical power distribution system were located in this building. These components had been included in the scope of the Rule because failure of these SSCs could potentially cause a reactor trip. The team discussed the concern that failure of this structure could cause failure of components located in the building with members of licensee management. As the result of this concern the licensee issued Deviation Report (DR) N-097-1940 during the inspection to require inclusion of this structure within the scope of the Maintenance Rule.

- The licensee had not included the hydrogen (H2) recombiner enclosure in the scope of the Maintenance Rule. Further review determined that various post accident H2 removal system components were located in that building. The HC (post accident hydrogen removal) system was included in the scope of the Rule because the system was classified as safety-related. The team discussed the concern that failure of this structure could have resulted in the failure of SSCs located in the structure with members of licensee management. The licensee also included this deficiency in DR N-097-1940 to require inclusion of this structure within the scope of the Maintenance Rule.

- The licensee had included in the scope of the Rule any control room annunciators which the licensee had considered to provide information needed for significant mitigation of accidents in the North Anna EOPs. However, the team noted several examples of other annunciators which provided additional important information to licensed operators during plant transients or accidents which had not been scoped in the Rule. The team discussed this concern with members of licensee management. As a result of this concern the licensee issued commitment tracking number 02-97-2250-001 to require a review of additional plant annunciators for inclusion under the Rule. This action was scheduled to be completed by North Anna Station Engineering before December 10, 1997.

The team verified that the licensee had taken action to include the above two structures within the scope of the Rule. The team reviewed the meeting minutes for the Maintenance Rule working group meeting held on October 7, 1997, and noted that the approval to add these two structures to the scope of the Rule had occurred during that meeting. Additionally, the licensee had completed the associated baseline walkdowns and taken necessary actions to add new Maintenance Rule functions to their scoping matrix for these structures prior to completion of this inspection.

Based on the minor risk significance associated with the oversight of the above two structures, the licensee corrective actions, and the reasonableness of licensee efforts to implement the Rule, the team concluded that the licensee appropriately addressed the team's concerns. The adequacy of scoping of plant annunciators will be reviewed during a future NRC inspection after the licensee completes the planned review of plant annunciators for inclusion under the Rule. NRC review of the Re-scoping of annunciators is identified as example one of IFI 50-338, 339/97-08-01, Followup Licensee Actions With Regard to PRA, Assessing Impact on Risk Ranking, Goals and Performance Criteria for Implementation of the Maintenance Rule.

c. Conclusions

Required SSCs were included within the scope of the Rule with the exception of two structures and several annunciators.

M1.2 Safety or Risk Determination

a. Inspection Scope (62706)

Paragraph (a)(1) of the Maintenance Rule requires that goals be commensurate with safety. Implementation of the Maintenance Rule using the guidance contained in NUMARC 93-01 requires that safety be taken into account when setting performance criteria and monitoring under Section (a)(2) of the Rule. This safety consideration would then be used to determine if the SSCs should be monitored at the train or plant level. The team reviewed the methods that the licensee had established for making these required safety determinations. The team also reviewed the safety determinations that were made for the functions that were reviewed in detail during this inspection.

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

In addition to determining which SSCs were within the scope of the Rule, the licensee's expert panel initially established the risk significance ranking of SSCs, established performance criteria of SSCs, determined which SSCs were (a)(1) and which were (a)(2), and established goals for the (a)(1) SSCs. When this effort was complete, the licensee disbanded the expert panel and established the Maintenance Rule working group. The working group assumed responsibility for most Maintenance Rule implementation activities.

The final risk significance ranking was based on a combination of results from a PRA and expert panel or Maintenance Rule working group judgement based on deterministic considerations. The licensee used quantitative measures of risk achievement worth (RAW), risk reduction worth, and core damage frequency contribution (CDF) that were consistent with the guidance provided in NUMARC 93-01. In addition, North Anna also considered the large early release frequency contribution. Both Level 1 and Level 2 analyses were used by the expert panel. The expert panel considered that all FEGs that met the NUMARC 93-01 criteria were risk significant. Additionally, the expert panel added several SSCs to the risk significant list. For example, the recirculation spray and feedwater (FW) systems were added to the risk significant category.

Due to issues regarding the quantification of risk importance measures and PRA modeling assumptions, the team was not able to determine if the licensee had adequately established the risk ranking of FEGs within the scope of the Maintenance Rule (Section M1.2.b.2), set goals commensurate with safety under (a)(1) of the Maintenance Rule (Section M1.2.b.3), or established performance criteria under (a)(2) of the Maintenance Rule (Section M1.2.b.4). The team was able to conclude that the plant was being safely operated in consideration of risk. NRC review of licensee actions related to the above issues is identified as example two of IFI 50-338, 339/97-08-01, Followup Licensee Actions With Regard to PRA, Assessing Impact on Risk Ranking, Goals and Performance Criteria for Implementation of the Maintenance Rule. These issues are described in the subparagraphs which follow.

b.1 Background

The licensee has performed several PRAs for the North Anna Power Station. The first study was completed in 1992 as part of the site Individual Plant Examination (IPE). This study used plant specific data covering the time period from 1986 to 1989 for equipment unavailabilities resulting from testing and maintenance. Mostly generic data were used for demand failure probabilities. Plant specific data was used to Bayesian update generic data for several safety related SSCs such as the emergency diesels, auxiliary FW and the low head safety injection system. The 1992 PRA estimated the CDF to be about 6.8E-5/reactor year, excluding the internal flood contribution.

In 1995, the licensee updated the North Anna PRA model. The most significant changes to the model were the addition of the station blackout (SBO) diesel and an alternate cooling supply to the emergency switchgear heating ventilation and air-conditioning system. With few exceptions, the test and maintenance unavailability and demand failure probabilities in this update were the same values used in the 1992 PRA. The 1995 PRA estimated CDF to be about 4.1E-5/reactor year excluding the internal flood contribution.

In 1996, as part of North Anna's Maintenance Rule rebaselining effort, the licensee performed further PRA calculations. The results of these calculations were used as an input to the expert panel/working group for establishment of FEG risk ranking, goal setting and performance criteria. The licensee's process was documented in Calculation SM-1045, "PSA Model Quantification North Anna Power Station Units 1 & 2." The team found that the licensee used a bounding analysis approach to derive these inputs to the expert panel. The licensee quantified the North Anna 1995 PRA model using three different sets of test and maintenance unavailability.

The first quantification was performed using test and maintenance (unavailability) basic events set to zero (i.e. modeled FEG was always available). The demand failure probabilities were not changed. Calculation SM-1045 called this case study TM-0 or the zero maintenance configuration case. Case study TM-0 estimated the internal event CDF to be about 3.9E-5/reactor year excluding the internal flood contribution.

The second quantification used the risk ranking results from the TM-0 case to assign test and maintenance unavailability probabilities to the FEGs. Unavailability was based on the FEG's RAW value, with the FEGs with higher RAW values given lower unavailability probability. The demand failure probabilities were not changed. The licensee then adjusted and requantified the PRA model until the estimated internal event CDF was approximately 7.1E-5/reactor year. This CDF was approximately equal to the IPE estimate. Calculation SM-1045 referred to this case as TM-2. Calculation SM-1045 described the TM-2 study as a bounding analysis that could be used to establish goals for FEGs once a FEG exceeded its Maintenance Rule unavailability performance criteria.

The third study was quantified using half of the test and maintenance unavailability probabilities used in the TM-2 case. The demand failure probabilities were not changed. This case was referred to as TM-1. The TM-1 case estimated internal event CDF was about 5.3E-5/reactor year excluding the internal flood contribution. Calculation SM-1045 stated that the Maintenance Rule unavailability performance criteria were to be established at the unavailability values from the TM-1 case.

b.2 <u>Risk Ranking</u>

As stated above, there were several issues that affected the risk ranking of FEGs within the scope of the Maintenance Rule. The first issue involved the method the licensee used to perform the risk ranking.

The licensee used a bounding approach rather than using PRA that provided a best estimate of actual plant risk. This was contrary to current industry practice and guidance. NUMARC 93-01 references EPRI Report TR-105396, "PSA Application Guide," as a reference source for establishing SSC risk significance. This report recommends that the PRA analysis be performed on a model that best represents the actual plant. In addition, the EPRI report only recommends using a bounding analysis to determine risk importance measures when single events are affected within the model.

Following questions from the team regarding the adequacy of the approach used for risk ranking, the licensee performed an additional PRA quantification using the most recent three year average FEG unavailability. The demand failure probabilities were not changed from the 1992 PRA values. The licensee estimated the internal event CDF to be about 4.3E-5/reactor year, excluding the internal flood contribution. Examination of the importance measures from this PRA analysis did not identify any new PRA risk significant FEGs. However, the team noted that while the most recent FEG unavailability data were used in this quantification, the licensee had used demand failure probability data that had not been updated since the IPE. Therefore, it was not clear whether this PRA quantification reflected the best estimate of risk importance measures.

Another issue was found which involved the licensee's identification of problems with the North Anna PRA model. In June of 1997, the Maintenance Rule expert panel identified a number of PRA model concerns and enhancements. These issues were documented in corporate Potential Problem Report (PPR) 97-017. The issue included the use of potentially inappropriate test and maintenance unavailability data, modeling of system dependencies, and areas where the PRA model did not reflect the as-built or as-operated plant. The PPR grouped the issues into three categories: short term (less than one month for corrective action), medium term (one to three months for corrective action), and long term (expected to take up to one year to implement). During the inspection, the licensee stated that only short term items associated with availability data had been addressed. Neither the licensee nor the team could assess the effect on risk ranking of the many unresolved issues addressed PPR 97-017. The licensee informed the team that they plan to revise the North Anna PRA model during the first quarter of 1998 to support their implementation of an on-line computerized risk monitoring system.

b.3 Goal Setting

Section (a)(1) of the Maintenance Rule requires, in part, that licensees establish goals that are commensurate with safety. The team found inconsistencies in licensee's staff perception of what constituted unavailability goals "commensurate with safety." As described above, SM-1045 described the test and maintenance unavailability assumptions used in the TM-2 case study that could be "used to establish goal setting for FEGs once they have exceeded their Maintenance Rule unavailability performance criteria." In addition, the licensee's PRA group provided Engineering Transmittal NAF-97-0206, "PSA Evaluation of New Unavailability Performance Criteria," Revision 0, that provided a table that listed PRA recommended unavailability goal setting values that were derived from the TM-2 case study. The team interviewed some Maintenance Rule working group members who stated that listed values in NAF-97-0206 were commensurate with safety since the goals would not result in exceeding the IPE CDF of 7E-5/reactor year. The team reviewed (a)(1) assessments associated with several of the unavailability goals that the Maintenance Rule working group had established for FEGs that had exceeded their unavailability performance criteria. Several of these documents contained statements that stated that the unavailability goal was commensurate with safety because it limited the unavailability time to a level below the unavailability that would result in an increase in CDF.

Other members of the licensee staff including the corporate Maintenance Rule coordinator had a different perception of what constituted unavailability goals that were commensurate with safety. These staff members stated that the unavailability performance criteria derived from the TM-1 case study should be used to establish unavailability goals commensurate with safety. The corporate Maintenance Rule coordinator stated that the statements in the above reviewed assessments were in error and would be corrected. Furthermore, the licensee was able to demonstrate to the team that the unavailability goals that had been established did not exceed the associated FEG's unavailability performance criteria.

Despite this clarification, the team was not able to assess the adequacy of the North Anna's Maintenance Rule unavailability goal setting. As described below, North Anna linked unavailability performance criteria to a FEG's RAW value. Due to the issues identified above with the North Anna PRA model that could affect the risk ranking of FEGs, the established unavailability performance criteria could be inaccurate, and therefore the unavailability goals may not be commensurate with safety.

b.4 <u>Performance Criteria</u>

NUMARC 93-01 states, in part, that performance criteria for risk significant SSCs should be established to assure that the reliability and availability assumptions used in the PRA are maintained. In general, the licensee elected to establish performance criteria that were less conservative than the North Anna PRA assumptions. The team was not able to determine if the licensee had established adequate reliability or unavailability performance criteria.

The licensee used WCAP-14759, "Work Plan for Performing On-line Maintenance," Revision 0, as guidance when establishing unavailability performance criteria. Using the TM-0 case study, the licensee established unavailability performance criteria based on the FEG's RAW. In general, FEGs with RAW values less than 2 were assigned an unavailability performance criterion of 438 hours/year. FEGs with RAW values between 2 and 5 were given an unavailability performance criterion of 175 hours/year. FEGs with RAW values greater than 5 were assigned an unavailability performance criterion of 87 hours/year.

The team found the licensee's approach to establish unavailability performance criteria was reasonable. As seen from the TM-1 case, if the unavailability criteria were used in place of the North Anna PRA test and maintenance basic events, the resultant increase in CDF would be relatively small (about 25 percent). However, due to the issues identified above regarding risk ranking and since the licensee linked the unavailability performance criteria with risk ranking results, the team could not determine if the unavailability performance criteria were adequate.

At the time of the inspection, the licensee was still in the process of establishing reliability performance criteria. Prior to the inspection, through the use of sensitivity studies, the licensee found that the values chosen for reliability performance criteria would result in an undesirable level of risk. The licensee stated that further changes in reliability performance criteria were needed. The licensee had captured this concern as an open item from their Maintenance Rule Post Recovery Assessment. Since the licensee was in the process of adjusting the reliability performance criteria, the team could not determine if reliability performance criteria were adequate.

For several FEGs, the licensee assigned a performance criteria of zero maintenance preventable functional failures (MPFFs). For these FEGs, the licensee elected to use condition monitoring to detect degradation. However, the team found that the licensee had not established condition monitoring performance criteria. This problem had already been identified by the licensee and was an open item from the North Anna Post Recovery Assessment. In addition, the licensee stated that since they were still in the process of establishing reliability performance criteria, Maintenance Rule condition monitoring for some of the FEGs may not be needed. Since the licensee was in the process of adjusting the reliability performance criteria, it was not clear to the team which FEGs would require condition monitoring.

b.5 <u>Expert Panel</u>

The licensee's procedure for implementation of the Maintenance Rule (VPAP-0815) identified a Maintenance Rule expert panel and a Maintenance Rule working group. The expert panel was responsible for the initial identification of FEGs within the scope of the Maintenance Rule and determination of which FEGs were risk significant. The licensee stated that the expert panel met continuously from March 1997 to June 1997 during the Maintenance Rule rebaselining effort. The expert panel has not met since June 1997. The expert panel quorum required by Corporate Procedure VPAP-0815, "Maintenance Rule Program," Revision 6, included representatives from operations or maintenance, engineering, a corporate PRA supervisor, and the corporate Maintenance Rule coordinator. Additionally, VPAP-0815 requires that both Virginia Power nuclear sites (North Anna and Surry) be represented and at least one member has a senior reactor operator (SRO) background.

The Maintenance Rule working group provided an ongoing review of Maintenance Rule activities and was responsible for performing the following Maintenance Rule activities:

- Reviewing and approving SSC scoping changes.
- Reviewing and approving performance criteria for risk significant and Maintenance Rule SSCs,
- Reviewing and approving Maintenance Rule procedure revisions,
- Reviewing and approving disposition of SSC from (a)(2) to (a)(1) and from (a)(1) to (a)(2),
- Reviewing and approving (a)(1) evaluations, and concurring with corrective actions and goals, and
- Reviewing and approving SSC performance trends against their performance criteria.

The members of the Maintenance Rule working group had extensive experience. Voting members of the working group included supervisors from component engineering, system engineering, operations, outage planning and scheduling, nuclear safety analysis, and nuclear safety. Many panel members were either registered professional engineers or previously licensed SROs.

The team noted that, unlike the expert panel, there was not a PRA expert assigned as a permanent member of the working group. The team interviewed two members of the working group and determined that their PRA knowledge was weak. Neither member was aware of the plants' CDF, and one member could not tell the team what was meant by the term risk achievement worth. The interviewed members stated that they had received less than one hour of PRA training. It did not appear that the Maintenance Rule working group had sufficient knowledge of the North Anna PRA to compensate for the PRA's limitations. The team considered that lack of a PRA expert as a voting member was a program weakness. In response, while the team was onsite, the licensee revised VPAP-815 to require a PRA expert to be a voting member of the working group.

The team observed a working group meeting during the inspection. The majority of the meeting was focused on equipment performance issues and considerations for removing a FEG from an (a)(1) status. The rigor and depth of discussions during the observed working group meeting were appropriate for the matters discussed.

c. Conclusions

The licensee and the NRC identified significant problems in the North Anna PRA. Because of these problems the team could not determine the quality of Maintenance Rule implementation with regard to risk ranking, goal setting and performance criteria. The team was able to conclude that the plant was being safely operated in consideration of risk (Sections M1.2.b.2, M1.2.b.3, and M1.2.b.4).

In addition, the licensee had not established condition monitoring performance criteria for several SSCs for which the performance criteria was zero failures (Section M1.2.b.4). The PRA knowledge of interviewed working group members was weak. Due to a lack of understanding of the North Anna PRA, the Maintenance Rule working group did not appear to be able to compensate for the PRA's limitations. A permanent PRA member was assigned to the working group during the inspection to correct this weakness. The rigor and depth of discussions during an observed working group meeting were appropriate for the matters discussed (Section M1.2.b.5).

M1.3 Periodic Evaluation

a. Inspection Scope (62706)

Paragraph (a)(3) of the Rule requires that performance and condition monitoring activities and associated goals and preventive maintenance (PM) activities be evaluated, taking into account, where practical, industry-wide operating experience. This evaluation is required to be performed at least one time during each refueling cycle, not to exceed 24 months between evaluations. The team reviewed the licensee's periodic evaluation process.

b. Observations and Findings

The team noted that program guidance for the periodic evaluations was found in VPAP-0815, "Maintenance Rule Program," Revision 6. The team reviewed the guidance and found that all elements of the required periodic evaluations were addressed. The team discussed with the licensee that the guidance was written at a high level and did not address responsibilities or how the evaluations were conducted. The licensee stated that more detailed draft guidelines existed but would not be completed until November 1997.

The licensee had completed several program assessments in 1997 due to self- and NRC-identified program deficiencies. The licensee also formed a Maintenance Rule Recovery Team (MRRT) to ensure identified program deficiencies were properly addressed. The team reviewed these assessments and concluded that the program assessments and recovery efforts collectively met the requirements of a periodic assessment. These assessments and recovery efforts were completed in September 1997. The MRRT assessment was documented as Technical Report No. EP-0006, "Maintenance Rule Recovery Team Final Report," Revision 0, dated August

1997. The licensee plans to perform the first formal periodic evaluation after the next Unit 2 outage in May 1998.

c. Conclusions

The team concluded that the licensee had met the requirements of the Rule for periodic assessments.

M1.4 Balancing Reliability and Unavailability

a. Inspection Scope (62706)

Paragraph (a)(3) of the Rule requires that adjustments be made where necessary to ensure that the objective of preventing failures of SSCs through PM was appropriately balanced against the objective of minimizing unavailability of SSCs as the result of monitoring or PM. The team discussed with responsible personnel the licensee's methodology for and history of balancing reliability and availability.

b. Observations and Findings

The team reviewed the licensee's approach to balancing system reliability and unavailability for risk significant systems to achieve an optimum condition. The licensee had scheduled balancing reviews during periodic evaluations at refueling outages, not to exceed 24 months. The requirements for balancing reliability and unavailability were discussed in the licensee's procedure VPAP-0815, "Maintenance Rule Program," Revision 6. The system engineers, station Maintenance Rule coordinator, and the station nuclear safety supervisor were responsible for the evaluation balancing process for risk significant systems during periodic system evaluations. The Maintenance Rule coordinator was also responsible for collecting data from the system engineers.

The team reviewed the licensee's process for balancing a function's reliability and unavailability. The licensee's approach consisted of monitoring SSC performance against the established SSC performance criteria. The process considered a function balanced if the performance criteria were met. This method was in accordance with NUMARC 93-01.

As stated in section M1.2 above, the licensee had not adequately established performance criteria for several risk significant SSCs. Therefore, at the time of this inspection, the team concluded that the licensee may not have correctly balanced those systems.

c. Conclusions

The team concluded that the licensee's approach of balancing reliability and unavailability met the intent of paragraph (a)(3) of the Rule. However, since the licensee had not established adequate performance criteria for several risk significant systems, balancing reliability and unavailability for those SSCs would not be possible.

M1.5 Plant Safety Assessments Before Taking Equipment Out-of-Service

a. Inspection Scope (62706)

Paragraph (a)(3) of the Maintenance Rule stated that the total impact on plant safety should be taken into account before taking equipment out-of-service for monitoring or PM. The team reviewed the licensee's procedures and discussed the process with plant operators, shift technical advisors, schedulers, and PRA engineers. The team also reviewed safety assessments that the licensee had made for several past plant configurations.

b. Observations and Findings

The team reviewed the licensee's processes for removing equipment from service. Procedure VPAP-2001, "Station Planning and Scheduling", Revision 5 described the safety assessment process for removing equipment from service while the plant(s) was operating. Procedure VPAP-2805, "Shutdown Risk Program", Revision 2 described the licensee's process to assess safety when a plant was shutdown.

Procedure VPAP-2001 required that safety assessments be performed prior to performing online PM activities. This assessment was normally performed by North Anna's maintenance schedulers while developing the site's monthly/weekly maintenance schedules. Safety assessments for emergent maintenance activities were performed by onshift SROs if maintenance schedulers were not on the site.

The team found that the licensee generally used risk insights to assess the safety of proposed plant maintenance configurations. The licensee's PRA group had developed three tools to assist in making these safety assessments. Engineering Transmittal NAF-97-0191, "On-Line Maintenance Risk Significant Functional Equipment Group Data," Revision 1 provided a list of PRA on-line maintenance risk significant equipment. This document described the risk (both instantaneous and cumulative) associated with the removal of a single on-line maintenance risk significant FEG. The licensee considered a FEG to be on-line maintenance risk significant if the FEG had a RAW value of greater that 1.026 as quantified using a PRA model with all test and maintenance basic events set to zero. The licensee calculated the risk associated with the removal of an on-line maintenance risk significant FEG from service based on the FEG's contribution to risk.

Procedure VPAP-2001 required a PRA evaluation be performed when two or more on-line maintenance risk significant FEGs were scheduled to be out of service simultaneously. The licensee's PRA group would then evaluate the proposed plant configuration. The PRA group requantified the PRA based on the proposed plant configuration to determine the risk significance of that particular configuration. In order to provide risk insights for possible emergent maintenance or failures, the PRA group also identified the additional risk associated with that plant configuration and the removal of one additional on-line maintenance risk significant FEG. The risk associated with the loss of an additional FEG was based upon its RAW value from the configuration recalculation. The PRA group documented the results of these risk assessments in Engineering Transmittal NAF-97-0024, "On-Line Maintenance Configuration Matrix," Revision 25. This document was then used by schedulers and operators. The team found that the PRA group updated this document each time a plant maintenance configuration was proposed that had not been previously evaluated.

Due to shared systems between units, the licensee developed a third tool. This was Engineering Transmittal NAF-97-0192, "On-Line Maintenance Configuration Matrix for Outages North Anna, Units 1&2," Revision 0. This transmittal documented safety assessments for on-line plant maintenance configurations when one unit was shutdown and the other was operating.

The licensee calculated a recommended allowed out-of-service time based on maintaining a cumulative impact on CDF for each configuration of less than 1E-6. A red risk category represented an equipment configuration that would have a risk recommended out-of-service time of less than or equal to 24 hours. Orange configurations would have a risk recommended out-of-service time of greater than 24 hours and less than or equal to 72 hours. Yellow configurations had a recommended risk out-of-service time of greater than 72 hours and less than or equal to 168 hours. Green configurations had a risk recommended out-of-service time of greater than 168 hours. The team noted that this categorization was consistent with current industry guidance.

The team could not determine the adequacy of these tools due to questions regarding North Anna's PRA model and associated risk ranking. The risk ranking of FEGs could change when the licensee makes the needed changes to the North Anna PRA model. The NRC review of this issue is identified as example three of IFI 50-338, 339/97-08-01, Followup Licensee Actions With Regard to PRA, Assessing Impact on Risk Ranking, Goals and Performance Criteria for Implementation of the Maintenance Rule.

The maintenance schedulers and operators who were interviewed all demonstrated a good understanding of how to use the above tools to determine the risk associated with a particular plant configuration. In addition, the team found the licensee's PRA group was routinely contacted by both schedulers and operators when questions arose or when a new plant configuration required a risk evaluation.

The team reviewed operator logs, limiting conditions for operations logs and clearance logs for the period between July 20, 1997 and September 19, 1997. The team found that the licensee had performed safety assessments according to VPAP-2001 prior to entering all on-line maintenance risk significant plant configurations.

The team found that the licensee's process for performing safety assessments for on-line plant maintenance configurations was comprehensive and effectively implemented, except for one minor weakness. The on-line safety assessments that involved non risk significant FEGs did not receive a risk informed assessment even though many of these FEGs were modeled in the licensee's PRA. For these configurations, the supervisor of North Anna's planning group performed the safety assessment based on his expert judgement. The licensee informed the team that the site was planning to install computerized risk monitors that would permit the site to perform risk quantifications for all plant maintenance configurations that were modeled in the PRA. The team concluded that this would correct this minor process weakness.

The licensee implemented a separate shutdown safety assessment process for planned outages. This process was described in VPAP-2805, "Shutdown Risk Program," Revision 2. The licensee's shutdown safety assessment process took into account the need to maintain certain critical safety functions during shutdown operations. These functions included reactivity control, electrical power, inventory control, containment integrity, and decay heat removal. The process allowed outage planners to schedule maintenance activities in a manner that would ensure the availability of the critical safety functions by redundant SSCs. The licensee's process for assessing shutdown risk was satisfactory.

c. Conclusions

The team concluded that the licensee had effectively implemented a comprehensive process for performing safety assessments for on-line maintenance activities. Because of the problems with the PRA, the team could not evaluate the adequacy of the licensee's risk assessment tools. Also, the maintenance schedulers and operators who were interviewed all demonstrated a good understanding of how to use the above tools to determine the risk associated with a particular plant configuration. One minor process weakness was identified regarding the lack of risk informed safety evaluations for some FEGs that were modeled in the North Anna PRA. The licensee's process for assessing shutdown risk was satisfactory.

M1.6 Goal Setting and Monitoring for (a)(1) SSCs

a. Inspection Scope (62706)

Paragraph (a)(1) of the Rule requires, in part, that licensees shall monitor the performance or condition of SSCs against licensee-established goals in a manner sufficient to provide reasonable assurance that the SSCs are capable of fulfilling their intended functions. The Rule further requires that goals be established commensurate with safety and that industry-wide operating experience be taken into account, where practical. Also, when the performance or condition of the SSC did not meet established goals, appropriate corrective action is to be taken.

The team reviewed the systems and components listed below for which the licensee had established goals for monitoring of performance to provide reasonable assurance that the system or components were capable of fulfilling their intended function. The team verified that industry-wide operating experience was considered (where practical), that appropriate monitoring was being performed, and that corrective action was taken when SSCs failed to meet goal(s) or when an SSC experienced an MPFF.

The team reviewed program documents and records for three SSCs that the licensee had placed in the (a)(1) category in order to evaluate this area. The team also discussed the program with licensee management, the Maintenance Rule coordinator, engineering and maintenance personnel, and other licensee personnel.

b. Observations and Findings

b.1 Alternate AC Diesel Generator (DG) (AAC)

The AAC system consisted of a single 3300kW DG and two busses, "M" and "L" capable of providing 4160vac backup power to either unit or to the station loads. The AAC system was identified as the required SBO source in 10 CFR 50.63, "Loss of all alternating current power." A description of the AAC system is in Chapter 9.5.11 of the UFSAR and surveillance requirements are in Section 3.8.11 of the technical specifications.

The stated Maintenance Rule purpose of the SBO DG was to provide a station backup power supply for either unit if there was a loss of power. The AAC system was classified as risk significant and not safety-related. The AAC system's Maintenance Rule function was to provide an alternate source of electrical power for one of the 4160vac emergency buses in either unit. In addition, it was also required to provide emergency power to the station loads. The Maintenance Rule function required the manual alignment of the SBO DG to the emergency buses within one hour through the "M" and "L" buses.

The performance criteria and goals were in accordance with NUMARC 93-01. The "L" bus provided connections to the transfer buses that connect to the safety-related emergency buses. The "M" bus provided connections from the DG to the "L" bus and station buses. The team verified that the unavailability time was logged at 141 hours for the "M" bus and zero hours for the "L" bus for the last 12 months. This was less than the 175 hour performance criteria. One MPFF was identified with the DG.

One failure of the reliability performance criteria of "0 MPFF" caused the AAC system to be classified as (a)(1). The MPFF was not in the AAC system itself; it was with an identical component in the unit 1 main turbine generator. The Units 1 and 2 main generators and the SBO DG used identical negative sequence relays in their protective circuits. On October 24, 1996, the Unit 1 main generator tripped due to a failure in the filter circuit of the negative sequence relay. The licensee's corrective action had been to perform plant modifications to correct the deficiency with all the relays of this type including the one in the SBO DG. The modification change was accomplished in conjunction with the recommendations from the relay vendor. The performance goals to return the AAC system to (a)(2) status were no unit trips caused by relay drift and acceptable relay drift during relay calibration for the next two refueling outages. The team concluded these goals met the intent of the Rule.

The team reviewed the work orders and deficiency reports for the last two years to ensure that all functional failures were identified and the unavailability time was logged. No deficiencies were noted by this review.

The team concluded the AAC system was properly classified as (a)(1) and the goals were adequate to return it to (a)(2) status.

b.2 High Head Safety Injection (HHSI)

The team focused its inspection on the primary flow path for HHSI. This flow path included the suction and discharge piping and associated valves, the HHSI pumps (otherwise known as the charging pumps), and components included within the FEG of the charging pumps. The charging pumps and their associated piping and valves were risk significant. The performance criteria for unavailability of the pumps was 438 hours for a single pump and 87 hours for two pumps out-of-service at the same time. Reliability performance criteria was one MPFF for the HHSI pump FEG. The Rule requirement for establishing performance criteria was met.

The charging pumps had been classified as an (a)(1) category SSC for the following reasons.

- Unreliable pump seals
- Unreliable lube oil temperature control valves (TCVs) [which was a SW system component included within the charging pump FEG]
- High unavailability

The team reviewed the current list of MPFFs and RMPFFs for systems scoped in the Rule and found that several existed for the HHSI system. The team also reviewed work orders and deficiency reports to determine if the licensee had properly tracked failures for the system. The team discovered during this review that the SW TCV MPFFs were being tracked with the SW system versus the HHSI system. After discussing this example with several engineers, it was evident that the concept of FEGs and tracking of MPFFs within those groups was not well defined by the licensee's program. The licensee initiated Commitment Number 02-97-2249-001 to enhance the program database and matrix to cross reference system functions.

Corrective actions for the charging pump issues were reviewed. Corrective actions included seal replacement with an enhanced design and maintenance work practice improvements associated with seal repair. The team asked if industry operating experience had been used for the charging pump seal issue. The system engineer stated that engineering had participated in a industry survey which had addressed the seal issue. Corrective actions for the SW valve problems involved a routine inspection for corrosion and sludge. These factors had been determined to be the causes of the valve failures. The corrective actions for the increased unavailability time were improvement in work practices and repair of leaking pump suction and discharge valves. The licensee stated that effective corrective actions for the SW valves and pump seals should also improve the availability of the charging pumps. The team concluded that the licensee had properly evaluated the unavailability and reliability issues and corrective actions were reasonable.

The team reviewed goals and monitoring established for the charging pumps and SW valves and found that the goals met the requirements of the Rule. The team noted that the goal for charging pump 1-CH-P-1B did not have an assigned date for pump seal replacement; pump 1-CH-P-1B was the last pump without the new seal design. This item was discussed with the licensee who took immediate action to assign a date of December 31, 1997. The team concluded that the replacement date was reasonable because pump seal performance had been satisfactory and was not currently leaking. While reviewing monitoring documentation for the seal issue, it was noted that specific monitoring techniques and frequencies had not been mentioned. This was discussed with the licensee who acknowledged the deficiency. Even though the documentation was not complete, the team was satisfied that adequate monitoring had been established. The monitoring included increased frequency of walkdowns by the system and the component engineers. Additionally, the charging pump cubicles were inspected daily by operators and health physics personnel during their routine tours. The team concluded that goals and monitoring established for the HHSI system adequately met Rule requirements.

b.3 DC Electrical System

The DC electrical system included the station batteries, chargers, 125 vdc buses, inverters, and 120 vac vital buses. The system had been classified as a normally operating risk significant system with some standby risk significant functions. The station battery chargers, dc bus 1-I, and 120 vac vital bus 1-I had been classified as (a)(1) on June 26, 1997, due to exceeding unavailability. The original PRA model had assumed a performance criteria of zero hours for each of these system components and had not allowed any unavailability for testing or routine maintenance. The Maintenance Rule working group subsequently approved the new performance criteria on September 23, 1997, and these components were returned to (a)(2) status. Actual unavailability times for system components was relatively low and the team did not identify any significant problems with the system. The team verified that the licensee had implemented goal setting and monitoring as required by paragraph (a)(1) of the Rule for the system.

c. Conclusion

As discussed in Section M1.2.b.3, the team was not able to conclude, due to PRA deficiencies, that goals for (a)(1) systems were commensurate with safety. However, the process for establishing goals was in place and was adequate for the systems reviewed. In general, industry wide operating experience was used. Corrective action for failures was adequate, and reliability and unavailability data were being properly captured for the SSCs reviewed. One weakness concerning the logging of failures against the appropriate FEG was identified.

M1.7 Preventive Maintenance and Trending for (a)(2) SSCs

a. Inspection Scope (62706)

Paragraph (a)(2) of the Rule states that monitoring as required in paragraph (a)(1) is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate PM, such that the SSC remains capable of performing its intended function.

The team reviewed selected SSCs listed below for which the licensee had established performance criteria and was trending performance to verify that appropriate PM was being performed, such that the SSCs remained capable of performing their intended function. The team verified that industry-wide operating experience was considered (where practical), that appropriate trending was being performed, that safety was considered when performance criteria were established, and that corrective action was taken when SSCs failed to meet performance criteria or when an SSC experienced an MPFF.

The team reviewed program documents and records for selected SSCs the licensee had placed in the (a)(2) category in order to evaluate this area. The team also discussed the program with licensee management, the Maintenance Rule coordinator, engineering and maintenance personnel, and other licensee personnel. In addition, the team reviewed specific program areas based on review of operator logs and equipment out-of-service logs.

b. Observations and Findings

b.1 Structures

The team selected the SW pump house, the SW valve house, the SBO DG Building, and both H2 recombiner rooms for review. The review included walkdowns for the evaluation of the concrete and structural steel components. The walkdown inspection results were compared with the licensee's findings and deficiency reports. In addition, the team reviewed the licensee's status of all structures. At the time of this inspection, the licensee had completed the inspections of all structures and buildings except the Unit 2 turbine building mezzanine and basement.

The licensee's inspection of these two areas was scheduled for completion by the end of 1997. The team concluded the inspection schedule was satisfactory.

The licensee's program for monitoring the condition of structures for the Maintenance Rule was implemented from the same program used for license renewal. This program was documented in Technical Report No. CE-0089, Revision 2, "Guideline for Monitoring of Structures North Anna Power Station", dated September 22, 1997. The guideline contained the inspection criteria for earthen structures, concrete structures, steel structures, masonry walls, ground water, inaccessible areas, seismic gap, and containment. Age-related degradation mechanism such as abrasion, erosion, chemical attack, leaching, settlement, thermal exposure, fatigue, and volume changes were addressed. The team concluded the guideline was comprehensive and contained all the necessary performance criteria requirements for monitoring structures.

The team reviewed the following documentation: 1) all the deficiency reports for all structures and buildings for the last two year period; 2) the initial condition assessment of plant structures and buildings that was performed July 1-3, 1996: and 3) Maintenance Rule Condition Assessment of Plant Structures Evaluation of Deviation Reports, dated July 28, 1997. The findings identified in these documents were examined during the walkdown inspections by the team. No major deficiencies were identified that would have placed any structures in the (a)(1) status.

The team concluded that the licensee had established a good program for monitoring structures to meet the intent of the Rule. The licensee had completed their initial walkdown inspections with the minor exceptions previously noted. During the walkdown inspections with the team, the licensee's civil engineering personnel exhibited exceptional knowledge and were very helpful in pointing out and discussing all aspects of potential deficiencies that could occur with the structures if not properly addressed.

The team concluded the licensee's program for monitoring structures was a strength in the Maintenance Rule program.

b.2 Post Accident H2 Removal System (HC)

The HC system was classified as a safety-related non-risk significant standby system. The HC system supports both units and is described in Chapter 6.2.5 of the UFSAR. The surveillance requirements are in Section 3.6.4 of the technical specifications. The system consists of two H2 analyzers, two H2 recombiners, containment purge blowers, and associated valves and piping that can be cross connected to either unit as required. Each H2 recombiner was installed in its own reinforced room. The Maintenance Rule functions and performance criteria were:

- 1) H2 analyzers monitor containment H2 concentration post LOCA - 2 MPFF/analyzer per year.

- 2) H2 recombiners maintain H2 concentration below flammable limits post LOCA - 2 MPFF/recombiner per year.

- 3) Purge blowers purge containment concentration to reduce gas post LOCA - 2 MPFF per year.

The team reviewed the testing and surveillance requirements to determine the number of opportunities the components had to operate satisfactory or fail. The testing included 1) a three month inservice inspection for the check valves; 2) a 18 month H2 recombiner functional test; 3) a 18 month H2 recombiner heater element periodic test; 4) a three month H2 analyzer calibration check; 5) a H2 recommbiner annual blower PM task; and 6) a 18 month electrical maintenance of motors. This testing in conjunction with the system performance criteria would permit up to a 50% failure rate. The team considered this to be a weakness. However, the technical specifications did require adequate corrective action be implemented for any deficiencies identified during surveillance testing.

The team reviewed the work orders and deficiencies to verify all functional failures were properly classified and adequate corrective action was implemented when required.

The team concluded the HC system was properly classified as (a)(2). Weaknesses were identified with the performance criteria.

b.3 Bearing Cooling (BC)

The BC system was identified by the expert panel as non-risk significant except for its supply to the FW and condensate (CN) systems. Cooling for the FW and CN pumps was considered risk significant for mitigation of operational transients. Performance criteria was 438 hours of unavailability and 2 MPFFs for each BC pump. Other BC system cooling loads were monitored with their associated loads. For example, BC cools the turbine lube oil coolers, therefore failures of BC affecting turbine lube oil were tracked with the turbine lube oil system. The BC header and cooling tower performance criteria were monitored by plant level performance criteria. The standby cooling tower fans had 2 MPFFs assigned to each fan. The BC system had the ability to bypass the cooling tower and use lake water for system cooling. This mode of operation had 2 MPFFs assigned for failures which prevented lake-to-lake cooling. Rule requirements for performance criteria were met.

The team reviewed the current list of MPFFs and RMPFFs for systems scoped in the Rule and found that one existed for the BC system. The team also reviewed work orders and deficiency reports to determine if the licensee had properly logged system failures. No discrepancies were noted during this review. The team requested the licensee to demonstrate the ability to provide the number of MPFFs for the BC cooling tower fans to determine if the licensee could readily access the information and to determine if the information was accurate. The team found that one fan had experienced an MPFF. This effort validated that the current list of MPFFs was accurate. The team also reviewed the number of unavailability hours logged against the BC pumps and found the hours to be well below the performance criteria of 438 hours. It was noted that the tracking of reliability performance criteria were not as effective and easily understood as the tracking of unavailability criteria. This difference was discussed with the licensee.

The team discussed the overall condition of the BC system with the system engineer. The engineer had been involved in several projects to improve the condition of the system. The engineer stated that the BC turbine lube oil TCV had caused problems for the turbine lube oil system. These problems had been repetitive. Corrective actions were reviewed for the TCV problems. The licensee and the vendor had determined that the TCV problems had been caused by the failure of an ambient temperature compensating coil. When the temperature of the area was cold (which had been caused by opening an outside door), the TCV would sense the colder air and throttle closed. The throttling closed of the TCV resulted in less cooling with a subsequent rise in turbine lube oil temperature. Once the coil was repaired, the problems no longer occurred. The licensee had previously initiated a request to periodically check the compensating coils for proper operation. Appropriate corrective action was taken once the problem was identified. The team questioned whether industry operating experience had been used to help solve the repetitive valve problems and the engineer stated that industry experience had not been used.

The team discussed system monitoring with the system engineer. The engineer stated that a monthly walkdown of the system was performed. The team reviewed the engineer's walkdown checklist and noted it to be thorough. The checklist noted specific problems with system performance and documented the review of various system performance indicators. The team noted that system trending was being performed for BC system temperatures and pressures. Additionally, the team found numerous examples of planned regular PM on miscellaneous system components. During a walkdown of the BC system, the team noted that vibration analysis was being performed on a BC pump. The team concluded that monitoring of the BC system was being performed and met the requirements of the Rule.

b.4 <u>Electro-Hydraulic Fluid Control (EHC)</u>

The team focused its inspection on the EHC pumps and associated components which provide high pressure hydraulic fluid for miscellaneous main turbine steam supply valves. This EHC system function was considered by the expert panel as non-risk significant. The performance criteria was 2 MPFFs for each EHC pump FEG. There was no unavailability criteria for the standby EHC pump FEG because this EHC system function was non-risk significant. The team discussed the basis for the performance criteria with the system engineer. The engineer stated that involvement of system engineering with the criteria had been minimal and that the number of MPFFs appeared "arbitrary." After discussions with the licensee on this issue, the team discovered that establishment of performance criteria had been done as a corporate effort with minimal input from site engineering.

The team reviewed the current list of MPFFs and RMPFFs for systems scoped in the Rule and found that none existed for the EHC system. The team also reviewed work orders and deficiency reports to determine if the licensee had properly tracked system failures. No discrepancies were noted during this review. There were numerous deficiency reports that had been initiated for main control room EHC low fluid pressure alarms. These deficiency reports were discussed with the system engineer who stated that the unloader valves for the EHC pump FEG had been "sticking," resulting in a pressure decrease to the low pressure alarm setpoint. The engineer stated that the function of the EHC system had not been lost because the pressure had not dropped low enough to cause the standby EHC pump to automatically start. The licensee was continuing to determine the root cause of the unloader valve sticking issue, but until the root cause was known, the licensee took appropriate corrective action by replacing the sticking unloader valves. The team questioned whether industry operating experience had been used to solve the unloader valve problems and the engineer stated that it had not been referenced.

Monitoring of the EHC system was being performed. The engineer stated that a monthly walkdown of the system was performed. Additionally, plant operators observed EHC system operation as part of their routine tours. A review of work orders determined that routine planned maintenance was performed on miscellaneous SSCs including, but not limited to, accumulators, heat exchangers, filters, valves, and instrumentation. Other procedures were provided by the engineer which showed that monitoring of the EHC system was occurring. The team concluded that category (a)(2) requirements were met for the EHC system.

b.5 Condensate System (CN)

The CN system had been classified as a normally operating risk significant system with some standby risk significant functions. Review of the CN system determined that appropriate performance criteria had been established and monitoring was being accomplished against those criteria. Review of the problems associated with the system determined that appropriate corrective actions had been taken for failures. Operating experience was being used in system monitoring. No deficiencies were noted concerning this system.

b.6 Rod Control System (RCS)

The RCS also included components from the control rod drive power supply system. This system had been classified as a normally operating non-risk significant system. However, the reactor trip breakers were considered as having standby risk significant functions. Review of the RCS system determined that appropriate performance criteria had been established and monitoring was being accomplished against those criteria. Review of the problems associated with the system determined that appropriate corrective actions had been taken for failures. Operating experience was being used in system monitoring. No deficiencies were noted concerning these systems.

c. Conclusions

As discussed in Section M1.2.b.4, the team was not able to conclude, due to PRA deficiencies, that performance criteria for (a)(2) systems were commensurate with safety. However, the process for establishing performance criteria, and monitoring against those criteria was adequate. In general, industry wide operating experience was used. Corrective action for failures was adequate, and reliability and unavailability data was being properly captured for the SSCs reviewed. One weakness concerning the appropriateness of the reliability performance criteria for the post accident hydrogen removal system was noted.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition Walkdowns

a. Inspection Scope (62706)

During the course of the reviews, the team performed walkdowns of selected portions of the following systems and plant areas, and observed the material condition of these SSCs:

- High Head Safety Injection System
- SW Pump House
- SW Valve House
- SBO DG and Building
- H2 Recombiner Rooms
- Bearing Cooling System
- EHC System
- Rod Control System
- Station Batteries
- Condensate System

b. Observations and Findings

The team performed material condition walkdowns on selected portions of each system that related to the areas inspected. Housekeeping in the general areas around systems and components was good. Piping and components were painted, and very few indications of corrosion, oil leaks, or water leaks were evident. The team observed the inside of selected panels and cabinets and no loose debris, damage, or degraded equipment were noted.

The team noted the following specific conditions during the walkdown inspection of SSCs:

- The relatively new SBO DG building was in excellent condition.
- The SW pump house main concrete floor was damaged in several places requiring a deficiency report to be written to address the problem.
- The H2 recombiner rooms were dirty and the sliding steel door, 1-BLD-DR RV73.2, stuck open and could not be closed.
- Minor oil leaks were observed at the BC pump bearing sightglasses, and equipment identification tags were missing at the BC supply to the main FW pumps.
- The general area around the EHC skids for both units was not clean. There were several minor oil leaks, some of which had not been properly documented.
- Some of the station battery cells contained a significant amount of sediment. This condition had been previously identified and was documented in DR 96-2635.

All of these conditions had been previously identified by the licensee or were immediately addressed once discussed with the licensee.

c. Conclusions

In general, walkdown of SSCs determined that they were being appropriately maintained.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self-assessment

a. Inspection Scope (62706)

The team reviewed the following self-assessments of the licensee's implementation of the Maintenance Rule:

- Sargent & Lundy Maintenance Rule Assessment Report (Performed December 9-20, 1996 - issued January 9, 1997)
- Maintenance Rule Team Report (Performed November 20, 1996, to January 9, 1997 - issued January 13, 1997) Note: This self-assessment included the above Sargent & Lundy Report as an attachment.
- Virginia Power Maintenance Rule Recovery Assessment (Performed May 19-23, 1997)

- Virginia Power Maintenance Rule Recovery Follow-up assessment (Performed July 21-28, 1997)

- Input to the Assessment of Maintenance Rule Implementation (Performed September 8-12, 1997 - issued September 16, 1997)

The team also held discussions with licensees' management concerning how the findings identified in the initial NRC Surry Maintenance Rule baseline inspection (NRC IR 50-280,281/97-01) were addressed during the redevelopment of the North Anna Maintenance Rule program. The team also briefly examined the report that addressed "The Review of the Management Aspects of Virginia Power's Maintenance Rule Implementation," dated February 21, 1997.

b. Observations and Findings

The team reviewed the assessments listed above during the week of preparation. Based on the review of the above subject licensee's assessments reports, the team concluded that the licensee was well aware of problems with their implementation of the Maintenance Rule. In fact, many of the issues identified in these assessments were also noted during this inspection. Further, the team noted the licensee had performed an implementation assessment of the Maintenance Rule and continued to assess the Maintenance Rule program prior to and throughout the recovery effort, a major redevelopment of the Maintenance Rule program. Five assessments and related follow-up activities were performed and reported on January 9, January 13, May 19, July 21, and September 21, 1997, by the licensee with outside experience and support. These assessments continued to validate the licensee's failure to adequately implement the Maintenance Rule, monitored the progress of the recovery effort, and identified numerous findings and needed enhancements to the program. These assessment and related reports were thorough and considered by the team to be a programmatic strength.

During this inspection, the team sampled several assessment findings to ensure that identified findings were appropriately handled and dispositioned. No major omissions were identified. Although not formally tracked, each of the items identified during the Maintenance Rule baseline inspection at Surry where within the responsibility of the recovery team's implied charter. However, the inspection team noted that the licensee did not have a systematic approach for closing out the items in their self-assessments. This lack of identifying specific assessment items, tracking and follow-up of self-assessment items was an indicated weakness. The majority of the findings, observations and enhancements had been addressed. However, throughout the on-site inspection week, there was a notable amount of confusion and lack of documentation as to the status of each assessment finding and also the status of the total number of assessment findings that needed to be addressed, corrected, verified and validated as closed. At the end of the inspection, there was a total of 64 assessments findings or enhancements that remained open and needed to be addressed by the licensee. Based on this weakness and related confusion as to the status of each of the assessment findings, the licensee issued three commitment data forms to track each of the assessments (i.e., 02-97-2245-001, 02-97-2246-001, and 02-97-2247-001).

c. Conclusions

The team concluded that the licensee had continued to perform self-assessments of Maintenance Rule activities. These assessments provided good observations, findings and needed enhancements of areas associated with Maintenance Rule implementation. These self-assessments of the Maintenance Rule program were thorough and considered a programmatic strength. Corrective actions sampled by the team were appropriately implemented. The team noted that the licensee did not have a systematic approach for closing out the items in their self-assessments. This lack of identifying specific assessments items, tracking and follow-up of self-assessment items was an indicated weakness.

II. OPERATIONS

04 Operator Knowledge and Performance

04.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection, the team interviewed one licensed reactor operator, two licensed SROs, two STAs, and one assistant shift supervisor to determine if they understood the general requirements of the Maintenance Rule and their particular duties and responsibilities for its implementation.

b. Observations and Findings

The operators were responsible for the following tasks associated with the Maintenance Rule:

- determining the impact on availability of SSCs when tagging equipment out-of-service and performing administrative requirements for tagging,

- evaluating the risk associated with shutdown operations,

- logging out-of-service SSCs in control room logs and minimizing SSC unavailability during maintenance activities,

- evaluating job scheduling activities and reviewing equipment configuration information in the Plan of the Day; and

- evaluating plant configurations to determine if work authorization created undue risk.

The operators interviewed understood the philosophy of the Maintenance Rule and their responsibilities associated with the Rule. The operators were adequately trained and understood the requirements of the applicable procedures. All operators understood the need to restore equipment to operating condition and to minimize SSC unavailabilities.

The team performed a review of two months of control room, limiting conditions for operation, and tagout logs from both units. The control room log entries examined contained the information necessary to extract out-of-service times for equipment, indicating the operations staff was sensitive to the importance of the control room logs as a source of information for Maintenance Rule record keeping.

As described in Section M1.5, the interviewed operators were familiar with the use of the licensee's on-line maintenance safety assessment tools. Operators primarily used the safety assessment tools to evaluate the risk associated with emergent maintenance activities or equipment failures. The operators were sensitive to the fact that maintenance activities could increase the frequency of initiating events.

c. Conclusions

Licensed operators understood their specific duties and responsibilities for implementing the Maintenance Rule. Licensed operators', and STAs' understanding of the use of their risk assessment tools for removal of equipment from service was good.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Updated Final Safety Analysis Report (UFSAR) Commitments (62706)

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special, focused review that compares plant practices, procedures and parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the team reviewed the applicable portions of the North Anna UFSAR that related to the areas inspected. The team verified that the UFSAR wording was consistent with the observed plant practices, procedures and parameters.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineering Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The team interviewed licensee personnel from the licensee's engineering organization for the SSCs reviewed in Sections M1.6 and M1.7 to assess their understanding of the Maintenance Rule and associated responsibilities.

b. Observations Findings and Conclusions

In general, system engineers' technical knowledge of their systems was sound. Recent reassignments contributed to some lack of system specific knowledge. System engineers understanding of the Maintenance Rule and its implementation was weak. The Virginia Power Maintenance Rule program was corporate driven with minimal reliance on the system engineers for implementation. This was different than most programs reviewed by the NRC.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The team leader discussed the progress of the inspection with licensee representatives on a daily basis and presented the results to members of licensee management and staff at the conclusion of the inspection on October 10, 1997. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

B. Foster, Superintendent Engineering
C. Funderburk, Superintendent Outage & Planning
E. Grecheck, Assistant Station Manager O&M
L. Hartz, Manager Nuclear Engineering
D. Heacock, Assistant Station Manager NS&L
P. Kemp, Supervisor Licensing
J. Leberstien, Station Licensing
L. Martin, Corporate Maintenance Rule Coordinator
W. Matthews, Station Manager
J. McCarthy, Manager Nuclear Licensing & Operations Support
R. McWhorter, Supervisor Auxiliary Systems
B. Morrison, Supervisor Electrical Systems
A. Parker, Station Maintenance Rule Coordinator
R. Rasnic, Supervisor Secondary Systems

NRC

D. Ashley, Operations Specialist, NRR
B. Bearden, Reactor Inspector, RII
S. Black, Chief, NRR/DRCH/HQMB
R. Correia, Section Chief, NRR/DRCH/HQMB
K. Coyne, Reactor Analyst, NRR
J. Flack, Chief, NRR/DSSA/SPSB
R. Gibbs, Senior Reactor Inspector, RII
R. Gibbs, Resident Inspector, RII
J. Jaudon, Director, Division of Reactor Safety, RII

M. Miller, Reactor Inspector, RII
M. Morgan, Senior Resident Inspector, North Anna, RII
J. Wilcox, Jr., Senior Operation Engineer, NRR
P. Wilson, Senior Reactor Analyst, NRR

OTHERS (Consejo De Seguridad Nuclear Spain, CNS)

Angle L. Coello Ortega, Nuclear Energy Advisor
Luis A. Gerez Matin, Nuclear Energy Advisor

LIST OF INSPECTION PROCEDURES USED

IP 62706 Maintenance Rule

LIST OF ITEMS OPENED

IFI 50-338, 339/97-08-01 IFI Followup Licensee Actions With Regard to PRA, Assessing Impact on Risk Ranking, Goals and Performance Criteria for Implementation of the Maintenance Rule (Sections M1.1, M1.2.b.2, M1.2.b.3, M1.2.b.4, and M1.5).

LIST OF DOCUMENTS REVIEWED

Virginia Power Administrative Procedure VPAP-0815, "Maintenance Rule Program," Revision 6

Virginia Power Administrative Procedure VPAP-2001, "Station Planning and Scheduling," Revision 2

Virginia Power Administrative Procedure VPAP-2805, "Shutdown Risk Program", Revision 2

General Nuclear Standard STD-GN-0008, "Equipment Mark Numbers," Revision 8

General Nuclear Standard STD-GN-0044, "Supplemental Maintenance Rule Guidelines," Revision 1

Engineering Transmittal ET No. CEP-97-0018, "Maintenance Rule Scoping and Performance Criteria Matrix, North Anna, Units 1 and 2," Revision 1

Engineering Transmittal NAF-97-0024, "On-Line Maintenance Configuration Matrix," Revision 25

Engineering Transmittal NAF-97-0191, "On-Line Maintenance Risk Significant Functional Equipment Group Data", Revision 1

Engineering Transmittal NAF-97-0192, "On-Line Maintenance Configuration Matrix for Outages North Anna, Units 1&2," Revision 0

Engineering Transmittal NAF-97-0206, "PSA Evaluation of New Unavailability Performance Criteria," Revision 0

Technical Report No. EP-0006, "Maintenance Rule Recovery Team Final Report," Revision 0

Technical Report No. CE-0089, "Guideline for Monitoring of Structures North Anna Power Station", Revision 2

WCAP-14759; "Work Plan for Performing On-line Maintenance," Revision 0

VIRGINIA POWER

North Anna Power Station
Maintenance Rule
October 6, 1997

ATTACHMENT

Maintenance Rule
Agenda

- Welcome - Bill Matthews
- NRC Entrance Presentation - Ron Gibbs

Maintenance Rule Program Presentation

- Introduction - Leslie Hartz
- Presentation

  Program Overview - Jack Martin
  On-Line Maintenance - George Marshall
  Assessments - Lucky Wroniewicz

Maintenance Rule
Inspection Logistics

- 0730 - NAPS Team Meeting
- 1600 - Team Meeting
- 1700 - Debrief

  NRC and Station Management

Maintenance Rule
Program Overview

- Program Responsibilities
- Program Document Overview
- Monitoring Overview

Maintenance Rule
Program Overview

Program Responsibilities

- System Engineering (SE)
- Station MR Coordinator (SMRC)
- Expert Panel (EP)
- MR Working Group (MRWG)
- Station Nuclear Safety (SNS)
- Civil Engineering (CE)
- Nuclear Safety Analysis (NSA)
- Corporate MR Coordinator (CMRC)
- On-Line Maintenance (later)

Maintenance Rule
Program Overview

Program Document Overview

- VPAP-0815 - Overall Program Administrative Control
- STD-GN-0044- Engineering Guidelines
- Scope, Risk Ranking, and Performance Criteria - Baseline Matrix (CEP-97-0018 and the Maintenance Rule Baseline Report)
- On-Line Maintenance - VPAP-2001
- Structures Guidelines
- Periodic Status Reports

Maintenance Rule
Program Overview

Monitoring Overview

- Normal Monitoring Identified Deviation Condition (Reliability and Unavailability)
- Deviation Report (SNS, SMRC, DART)
- Maintenance Rule Functional Failure (SE, SMRC)
- Maintenance Preventable Functional Failure (SE, SMRC)
- (a)(1) Evaluation (SE, SMRC, MRWG, ASM-O&M, SNSOC)

Maintenance Rule
On-Line Maintenance Program

- **VPAP-0815, Maintenance Rule Program**

  The Superintendent Outage and Planning is responsible for coordinating planing and scheduling activities on Maintenance Rule SSCs to minimize risk and maximize availability

Maintenance Rule
On-Line Maintenance Program

VPAP-2001, Station Planning and Scheduling

- Requirements for removing SSCs from service for on-line maintenance; includes requirements for SPA evaluations
- Details supervisory and management reviews of maintenance activities
- Requirements for quarterly, monthly, weekly and daily work schedules

Maintenance Rule
On-Line Maintenance Program

PSA guidance provided through:

- Engineering Transmittal NAF-97-0024, On-Line Maintenance Matrix
- Engineering Transmittal NAF-97-0191, On-Line Maintenance Risk Significant FEG Data Matrix [evaluates specific groups of FEGs available]

Maintenance Rule
On-Line Maintenance Program

Daily Work Management Process

- **0715 - Morning Status Review:**
  emergent issues/work requests/critical evolutions
- **1030 - Supervisors Planning Group**
  status of ongoing work
  review/discuss additions to the POD
- **1500 - Management Review Team:**
  Review of POD for next day
  Includes review of risk associated with on-line maintenance

[Meetings are held in Maintenance building conference room]

Maintenance Rule
On-Line Maintenance Program

Plan of the Day [POD]

- Presents risk profile for On-Line Maintenance
- Located on inside cover of the POD
- window based presentation of risk

  [RED / YELLOW / ORANGE / GREEN]

Maintenance Rule
On-Line Maintenance Program

Long Range Schedules

- Quarterly, Monthly, Weekly
- PSA insight from matrix used in development
- Evaluations from PSA requested as needed for configurations
- Management Review Team and Assistant Station Manager O&M approve weekly schedule
- Look ahead meeting Monday 1300 for next weeks critical maintenance items

Maintenance Rule
Post Recovery Assessment

- **Major Concerns:**
  - → Performance Criteria Non-Conservative
  - → Improve Documentation of (a)(1) Evaluations
  - → Reevaluate Scoping of Surry Switchyard
  - → Shutdown Issues
  - → Provide a Periodic Performance Report

Note: A deviation report has been filed at both stations to document these concerns

Maintenance Rule

Post Recovery Assessment

- **Other Short Term Recommendations:**

➔ Procedure Enhancements

➔ Aggressive Structure Inspection Plan

➔ On-Line Maintenance

  - Training
  - Communications

Maintenance Rule
Post Recovery Assessment

- **Strengths:**
  - ➔ Effective Guidance on Program Implementation
  - ➔ Involvement of the MRWG [at both sites]
  - ➔ Scoping and Risk Determination Appropriately Performed
  - ➔ On-Line Maintenance Program Implementation [Surry]
  - ➔ Technical Detail of Structural Guidelines