UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

August 21, 1996

EA 96-293

William L. Stewart, Executive Vice
President, Nuclear
Arizona Public Service Company
P.O. Box 53999
Phoenix, Arizona 85072-3999

SUBJECT: NRC INSPECTION REPORT 50-528/96-09; 50-529/96-09; 50-530/96-09

Dear Mr. Stewart:

An NRC inspection was conducted July 15-19, 1996, at your Palo Verde Nuclear Generating Station, Units 1, 2, and 3, reactor facilities with inoffice review continuing until August 20, 1996. This was an inspection of your implementation of the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" [the Maintenance Rule]. The enclosed report presents the scope and results of that inspection.

On August 16, 1996, a supplemental telephonic exit was held with Mr. S. Bauer and others of your staff to discuss enforcement findings from the inspection. A potential violation of NRC requirements was discussed during the telephonic exit. At that time, your staff presented additional information about the potential violation. Consequently, we reopened the inspection and reviewed the additional information. Resulting from that review, we concluded that the potential violation was not warranted. This result was discussed by telephone with Mr. S. Bauer on August 20, 1996.

Your program for implementing the requirements of the Maintenance Rule followed the guidance provided in NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated May 1993, which was endorsed in Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," dated January 1995. Your program was well developed, comprehensive, and generally met the requirements of the Maintenance Rule. Noteworthy aspects of your program were the methods used to monitor all functional failures of structures, systems and components, the expanded use of the expert panel, and the centralized data collection process.

One unresolved item was identified concerning goals and performance criteria for certain structures, systems, and components. This matter is discussed in Section M1.6 of the enclosed inspection report. No response to this item is necessary at this time.

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It is our understanding that, during the supplemental telephonic exit on August 16, 1996, Mr. Jim Levine stated Arizona Public Service Company would establish specific structures performance criteria within 90 days (of July 19, 1996), and review, and if necessary, revise procedures to clarify when structures should be moved to Category (a)(1). Please confirm this regulatory commitment in writing within 30 days of the date of this letter that our understanding of this commitment is correct.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure(s), and your response will be placed in the NRC Public Document Room (PDR).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

Kenneth E. Brockman

Kenneth E. Brockman, Acting Director
Division of Reactor Safety

Docket Nos.: 50-528
50-529
50-530
License Nos.: NPF-41
NPF-51
NPF-74

Enclosure:
NRC Inspection Report 50-528/96-09;
50-529/96-09; 50-530/96-09

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E-Mail report to D. Nelson (DJN)
E-Mail report to NRR Event Tracking System (IPAS)

bcc to DMB (IE01)

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ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-528 50-529 50-530
License Nos.:	NPF-41 NPF-51 NPF-74
Report No.:	50-528/96-09 50-529/96-09 50-530/96-09
Licensee:	Arizona Public Service Company
Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
Dates:	July 15-19, with inoffice review continuing to August 20, 1996
Team Leader:	R. Correia, Chief, Maintenance and Reliability Section Quality Assurance and Maintenance Branch Office of Nuclear Reactor Regulation
Assistant Team Leader:	J. Whittemore, Reactor Inspector, Region IV
Inspectors:	W. Holland, Senior Resident Inspector, Region II R. Langstaff, Reactor Inspector, Region III W. McNeill, Reactor Inspector, Region IV J. Williams, Reactor Inspector, Region I
Approved By:	Dr. Dale A. Powers, Chief, Maintenance Branch Division of Reactor Safety

ATTACHMENTS:

Attachment 1:	Partial List of Persons Contacted List of Inspection Procedures Used List of Items Opened
Attachment 2:	List of Procedures Reviewed

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EXECUTIVE SUMMARY

Palo Verde Nuclear Generating Station, Units 1, 2, and 3
NRC Inspection Report 50-528/96-09; 50-529/96-09; 50-530/96-09

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 covers a 1-week period of inspection by inspectors from the Office of Nuclear Reactor Regulation and Region I-IV.

Operations

- Licensed operators demonstrated an understanding of their specific duties and responsibilities for implementing the Maintenance Rule. However, their general understanding of the Maintenance Rule was weak (Section O4.1).

Maintenance

- All required structures, systems, and components except the radwaste building were included within the scope of the Rule, although it was included in the structures monitoring program. After discussions with the inspectors, the licensee included it within the scope of the Rule (Section M1.1).

- Plans for performing the periodic evaluation met the requirements of the Rule (Section M1.3).

- The approach to balancing reliability and unavailability was reasonable. However, the use of goals and performance criteria that differed from the original probabilistic risk assessment assumptions could limit the effectiveness of this approach (Section M1.4).

- Reasonable goals or performance criteria that took safety into consideration were set for most structures, systems, and components (Section M1.6).

  The following exceptions were noted:

  - The selected performance criteria for the containment and other structures and the lack of clear guidance for placing structures, systems, and components in Category (a)(1) or (a)(2) was a weakness and is an unresolved item.

  - The use of a quarterly failure trend data collection report to identify functional failures for the pressurizer and reactor vessel vent system was a weakness.

- The selected plant level performance criteria and monitoring for the steam bypass control system that did not reflect the actual ongoing system level monitoring and corrective actions was a weakness.

- Predictive monitoring and trending of appropriate parameters was being appropriately performed. Structures, systems, and components performance monitoring using functional failures and conservative trigger values in conjunction with performance criteria was considered a strength of the licensee's program. The use of a centralized data collection group to help ensure consistency and the collection of demand data (in addition to failure data) was considered a strength of. the licensee's program (Section M1.6.b.3).

- Maintenance and system engineers were very knowledgeable of their assigned systems and proactive in the development and implementation of corrective actions related to their systems. Root-cause analysis and corrective actions appeared to be a strength of the licensee's maintenance program (Section M1.6.b.4).

- In general, the material condition of the selected systems examined during the inspection was satisfactory. The gas turbines were in exceptional condition (Section M2).

- The scope of Self-Assessment Audit 96-020 was comprehensive and provided meaningful feedback to management (Section M7).

Engineering

- The risk determination process for structures, systems, and components was being performed in a satisfactory manner by an experienced and knowledgeable staff. Some weaknesses and strengths were noted (Section M1.2).

- The performance of plant safety assessments before taking equipment out-of-service was adequate. However, there was a weakness in the plant configuration risk indicator matrix that was used as part of these assessments. There was a potential for nonconservative estimates of risk associated with certain plant configurations and some balance-of-plant systems were not modeled in the probabilistic risk assessment (Section M1.5).

- Industry-wide operating experience was appropriately taken into consideration when setting goals and performance criteria (Section M1.6.b.2).

- All maintenance and system engineers interviewed were very knowledgeable of their assigned systems and demonstrated sufficient knowledge to adequately implement their responsibilities under the Maintenance Rule. However, some weaknesses in engineering staff knowledge of certain aspects of the Maintenance Rule were noted (Section E4).

Report Details

Summary of Plant Status

Units 1, 2, and 3 were at 100 percent power.

Introduction

The primary focus of this inspection was to verify that the licensee had implemented a maintenance monitoring program which satisfied 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 four region-based inspectors, and a team leader and six observers from the Quality Assurance and Maintenance Branch, Office of Nuclear Reactor Regulation, and two observers from the Probabilistic Safety Assessment Branch, Office of Nuclear Reactor Regulation.

I. Operations

04 Operator Knowledge and Performance

04.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection, the inspectors interviewed licensed operators to determine if they understood the general requirements of the Maintenance Rule and their particular duties and responsibilities for its implementation. The inspectors asked a sample of operators to explain the general requirements of the Maintenance Rule and to describe their responsibilities for implementing these requirements. The inspectors also reviewed the program dealing with licensed operator system approach to Maintenance Rule training.

b. Observations and Findings

The tasks associated with the Rule that operators were responsible for included:

- Determining the impact on availability of structures, systems, and components when tagging equipment out-of-service and performing administrative requirements for tagging.

- Determining structures, systems, and components out-of-service logging requirements and impact on availability.

- Evaluating priorities for system restoration.

- Evaluating job scheduling activities.

- Evaluating plant configuration to determine if work authorization created undue risk.

Operators understood the required duties for Rule implementation, which included logging in- and out-of-service equipment within the scope of the Rule and assessing the risk of emergent work items in accordance with the plant configuration risk indicator matrix. The inspectors reviewed selected operator logs for July 16 and 17, 1996, and verified Maintenance Rule availability log entries were being made as required. The inspectors verified the matrix was readily available to operators on Unit 2.

Although operators were knowledgeable of their duties associated with implementation of the Rule, the inspectors did not consider operators interviewed to be familiar with the purpose of the Rule. For example, when asked what the purpose of the Rule was, operators indicated the Rule would improve plant safety. However, they did not indicate the Rule was used to monitor performance of structures, systems, or components against goals or performance criteria and take appropriate corrective actions when goals or performance criteria were not met.

The inspectors also reviewed the training materials and noted that they appeared to reasonably address the operation's staff responsibilities. The training department management representative stated that training had been provided to the operators.

c. Conclusions

Licensed operators understood their specific duties and responsibilities for implementing the Maintenance Rule. However, general understanding of Maintenance Rule was weak.

II. Maintenance

M1 Conduct of Maintenance (62706)

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

a. Inspection Scope (62706)

Prior to the onsite inspection, the inspectors reviewed the Palo Verde Final Safety Analysis Report and Emergency Procedures Guidelines and selected an independent sample of structures, systems, and components that the inspectors believed should be included within the scope of the Maintenance Rule. Structures, systems, and components scoping criteria are described in 10 CFR 50.65 (b). During the onsite review, the inspectors used this list to determine if the licensee had adequately identified the structures, systems, and components that should have been included in the scope of their program.

b. Observations and Findings

The licensee appointed an expert panel to perform several Maintenance Rule implementation tasks including establishing the scope of the Maintenance Rule. They reviewed the 128 systems in the plant and determined that 89 structures, systems, and components were in the scope of the Rule.

The inspectors reviewed the licensee's database and verified that all required structures, systems, and components were included within the scope of the Rule except the radwaste building. The radwaste building is a nonsafety-related structure. However, in the licensee's scoping matrix, the radwaste building was listed as safety-related but not within the scope of the Rule. The inspectors noted that the radwaste building contained certain safety-related equipment and that failure of the radwaste building could result in the failure of these safety-related structures, systems, and components.

After some discussion, the licensee determined that the radwaste building should be included within the scope of Rule. The licensee stated that adding the radwaste building to the scope of the Maintenance Rule would not have an impact on their program because all the structures came under their structural monitoring program, which was used to implement the Maintenance Rule.

c. Conclusions

All required structures, systems, and components (except the radwaste building) were included within the scope of the Rule. After discussions with the inspectors the licensee included it within the scope of the Rule.

M1.2 Safety (or Risk) Determination

a. Inspection Scope

Paragraph (a)(1) of the Rule requires that goals be commensurate with safety. Additionally, implementation of the Rule using the guidance contained in NUMARC 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (which the licensee was using) required that safety be taken into account when setting performance criteria and monitoring under paragraph (a)(2) of the Rule. This safety consideration would then be used to determine if the structures, systems, and components should be monitored at the train or plant level. The inspectors reviewed the methods and calculations that the licensee had established for making these required safety determinations. The inspectors reviewed meeting minutes and attended an expert panel meeting. The inspectors also reviewed the safety determinations that were made for the systems that were reviewed in detail during this inspection.

b. Observations and Findings

The licensee established an expert panel in accordance with Section 9.3.1 of NUMARC 93-01, which described the use of the expert panel in the structures, systems, and components risk-determination process. Licensee Procedure 71DP-OEMO1, "Risk Management Program Expert Panel," Revision 0, described the licensee's program for evaluating risk for those structures, systems, and components within the scope of the Rule. The expert panel membership included representatives from maintenance support, probabilistic risk assessment, systems engineering, operations, scheduling and transient analysis. Alternates for each permanent member and Rules for a quorum were established. Additional engineering personnel were used on an as-needed basis. The expert panel possessed a total of 123 person-years of nuclear power experience.

In addition to determining which structures, systems, and components were within the scope of the Rule, the expert panel established risk significance ranking of structures, systems, and components; performance criteria of structures, systems, and components; goals of structures, systems, and components; and Category (a)(1) and (a)(2) structures, systems, and component lists. This use of the expert panel for these other activities, which were beyond the guidance in NUMARC 93-01, was considered to be a strength.

The final risk significance ranking was derived from a combination of probabilistic risk assessment data and expert panel judgment based on deterministic considerations. The licensee had used quantitative measures of risk achievement worth, Fussell-Vesely importance, and core damage frequency contribution. The risk rankings were both in terms of core damage frequency (Level 1 analysis) and large, early release frequency (Level 2 analysis). This original risk ranking identified 19 risk significant systems.

The licensee performed a self assessment (Audit Report 96-020) in May 1996 of its Maintenance Rule activities which identified that the process that had been used for the original risk ranking differed from the process specified in NUMARC 93-01. The licensee's management decided to perform the risk ranking process a second time using the methods recommended in NUMARC 93-01. These methods involved the use of an expanded interpretation of trip initiators and 90 percent core damage frequency contribution rather than the "Pareto Principle," which had been used in the earlier ranking process. This second risk ranking resulted in 16 additions to the high risk category for a total of 35 risk significant systems. The inspectors considered the self assessment, re-evaluation of risk determination and subsequent decision on the part of the expert panel to rank the additional structures, systems, and components as risk significant as a proactive and reasonable part of the on-going process of implementing the Rule.

After identifying the additional 16 risk significant systems, the licensee set a schedule for establishing system and train-level performance criteria for each of them following the NUMARC 93-01 guidance. At the time of the inspection, the licensee had established train-level performance criteria for 8 of the 16 additions to the high risk category, and was on schedule to complete the remaining 8 structures, systems, and components by September 5, 1996. The licensee appeared to have set a reasonable schedule for establishing performance criteria for these newly identified risk significant structures, systems, and components.

b.1 Risk Ranking Methodology

The inspectors reviewed the licensee's methodology for ranking structures, systems, and components which were within the scope of the Rule that followed the NUMARC 93-01 guidance. It was determined that the licensee had used the highest ranking component in each system as a surrogate for the system level importance. Thus, in determining the safety significance of a given system, the licensee assigned the Fussell-Vesely, risk achievement worth, or core damage frequency value of the highest ranked event as the value for the overall system importance. The inspectors concluded that this approach might not in all cases reflect the true "system" importance. For example, certain systems could have all the individual system components ranked slightly below the NUMARC 93-01 cutoff values, yet the system as a whole would be of greater importance than the single most important component. This effect could be observed empirically by manipulating the model and adjusting the relevant parameters of all of the system components according to the importance measure of interest and then recalculating the core damage frequency to reflect the "system" level importance. However, the licensee's software capabilities posed difficulties in calculating the actual system level performance using this approach.

The inspectors observed that, for most systems, the assignment of system importance based on the highest ranked component would represent an acceptable approach to system-level ranking. However, for those systems which were slightly below the cutoff values, additional measures were not taken to ensure that the appropriate importance levels are assigned. In particular, the expert panel was not made aware of this issue in making the final determinations of risk significance. For those borderline systems in which the expert panel may have been divided as to whether the system should be ranked high or low, the licensee could have performed the required calculations in order to arrive at a more accurate analytical estimate of the system importance.

The licensee representatives acknowledged that under certain scenarios, the use of the highest ranked component as a surrogate for system importance might not provide an appropriate estimate of system-level importance and that certain refinements in their risk ranking process were warranted.

In general, the inspectors found the assignment of system importance based on the highest ranked component would represent an acceptable approach to system-level ranking based on component level importance measures.

b.2 Truncation

Truncation limits are imposed on probabilistic risk assessment models in order to limit the size and complexity of the results to a manageable level. However, the benefits of truncation must be weighed against the potential consequences in that, if truncation limits are set too high, then certain events may be truncated which could result in underestimations of the importance of the affected events.

The inspectors reviewed the truncation limits, which had been established by the licensee in the solution of their probabilistic risk assessment model. It was determined that the licensee had used a cutset matching type of approach, whereby, the system-level fault trees were solved at a truncation level of 1E-08 (with the exception of the low pressure safety injection trees which were solved at 5E-07) and the event trees were solved at a truncation level of 1E-09. It was determined that the licensee had not performed sensitivity studies to determine whether the final rankings would be significantly affected by varying the truncation levels. The licensee's representatives indicated that such studies would represent an enormous analytical burden due to the nature of the calculations and their software capabilities.

The inspectors independently investigated the truncation effects on the final rankings and found that at least one additional system, Non-Class 1E instrument ac power would have exceeded the cutoff values for both Fussell-Vesely and risk achievement worth using the licensee's philosophy of assigning system-level importance to the highest ranking component within that system when a truncation level of 1E-12 was used. However, the inspectors noted that the licensee's expert panel had included the Non-Class 1E instrument ac power system among the high risk systems even though its Fussell-Vesely and risk achievement worth values were below the cutoffs. (The Non-Class 1E instrument ac power system did, however, rank in the top 90 percent core damage frequency cutset list). The inspectors determined that the licensee's approach to truncation with respect to the ranking process was adequate. Even though the expert panel's function was to compensate for probabilistic risk assessment limitations, the reliance on the panel to compensate for the lack of probabilistic risk assessment sensitivity studies was viewed as an area in which improvements could be made, such as sensitivity studies to validate that the final rankings would not be affected by truncation levels.

The inspectors determined that the licensee's approach to truncation with respect to the ranking process was adequate.

b.3 <u>Performance Criteria</u>

The inspectors reviewed the licensee's performance criteria which had been established for structures, systems, and components monitored under paragraph (a)(2) of the Maintenance Rule. It was determined that while the probabilistic risk assessment data and assumptions comprised an important input into the establishment of the criteria, it could not be demonstrated that the assumptions and data had been preserved in all cases. Thus, the potential existed that if certain structures, systems, and components reached or exceeded their performance criteria, the risk ranking results might be different from what was obtained in the original ranking. For example, the probabilistic risk assessment used an assumed maintenance unavailability probability for the gas turbine generators of 6E-03. However, the licensee's Maintenance Rule performance criteria used a value of 2E-01. The inspectors noted that this difference (for a single structure, system, and component) did not significantly affect the rankings. It was unclear, however, how the cumulative effects of many such differences would affect the ranking process when considered in the aggregate (i.e., if the performance criteria for many structures, systems, and components varied significantly from the probabilistic risk assessment data). It appeared that the licensee did not have a mechanism for feedback of the selected, probabilistic risk assessment-based performance criteria into the ranking process to ensure that the ranking results would not be affected by performance criteria which differed from that used in the probabilistic risk assessment.

The inspectors found that performance criteria were adequate. However, not incorporating the effects of reliability and unavailability assumptions (different from those assumed in the original ranking) was a weakness of the overall risk ranking methodology.

b.4 Use of Bayesian Updating Methodology

The inspectors noted that the licensee had used a Bayesian updating process to incorporate certain aspects of plant-specific data into the probabilistic risk assessment model for 22 structures, systems, and components. These were selected using a Birnbaum risk importance measure. It was determined that while the licensee had used a recognized methodology for performing such updating, the method used provided a very crude approximation of the results which would be achieved by more rigorous methods. The licensee had assumed lognormal prior distributions for the data to be updated using the Bayesian methodology. In order to perform the necessary calculations by hand, the licensee "fitted" a gamma distribution to the lognormal prior distribution using the "method of moments." This process preserved the mean and variance of the prior distribution, however, significant distortions can result. Data for 5 of the 22 selected structures, systems, and components were affected by this method.

This was illustrated by the licensee's updating of the frequency of the loss-of-turbine cooling water initiating event. The licensee's initial estimate for the frequency of loss-of-turbine cooling water initiating event was 2E-02/yr based on generic data (i.e., one occurrence every 50 years). An error factor of 14 was used by the licensee to estimate the variance of the prior distribution. By pooling plant-specific data across all three units, the licensee determined that no losses of turbine cooling water had occurred during 27.8 years of plant operation. Using the method of moments approximation as described above, the licensee updated the generic data and obtained a new mean frequency for loss-of-turbine cooling water initiating event of 2.6E-03/yr (i.e., one occurrence every 385 years). The inspectors determined that this result was not supported by the observed data.

Better approaches to updating generic data with plant-specific information were available. Such approaches include approximations, which preserve the desired probability intervals of the prior distribution, and numerical methods, which solve the updating problem directly. Independent calculations by the inspectors using these alternative methods and the licensee's data yielded an updated estimate of the loss-of-turbine cooling water initiating event frequency to be approximately 1E-02/yr (i.e., one occurrence every 100 years). The effect of these different estimates would be seen in the risk ranking results. In the case of loss-of-turbine cooling water initiating event, the impact of the different initiating event frequency estimates would have been to elevate the importance of turbine cooling water so that the NUMARC 93-01 cutoff values for high risk significance would be exceeded. (It should be noted that the licensee's expert panel had independently assessed the turbine cooling water system to be low risk.)

The licensee's representatives agreed that the method of moments approximation approach could yield potentially distorted results when updating lognormal distributions, particularly those with relatively large error factors. The licensee's representatives stated that a review of the Bayesian methodology and its effects on the risk ranking results would be conducted to ensure that no other underestimations had occurred.

The inspectors concluded that even though the licensee's method of updating probabilistic risk assessment data using plant specific data represented a mathematically acceptable approach, the method employed could, in some cases, distort the results due to the approximations which had been used.

The licensee's representatives agreed with the inspectors' assessment and stated that an alternate approach using numerical methods would be considered.

b.5 Expert Panel Observation

The inspectors observed the deliberations of the licensee's expert panel meeting on July 18, 1996. The agenda included a discussion on performance criteria of structures in general and specific classification of the radwaste building structure as Category (a)(2), the impact of reliability and unavailability performance criteria on probabilistic risk assessment assumptions, and the review of system basis documents.

The discussions of the expert panel reflected an in-depth review of the subjects and the major issues impacted by the Maintenance Rule. The inspectors found that expert panel was a strength of the licensee's program.

c. Conclusion

The risk determination was being performed in a manner consistent with the guidance of NUMARC 93-01. Some weaknesses were noted.

M1.3 Periodic Evaluation

a. Inspection Scope

Paragraph (a)(3) of the Rule requires that performance and condition monitoring activities and associated goals and preventive maintenance 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 inspectors reviewed the plans and procedures the licensee had established to ensure this evaluation will be completed as required. The inspectors also discussed these plans with the licensee's Maintenance Rule coordinator who was responsible for performing this evaluation.

b. Observations and Findings

At the time of the inspection, the licensee was not required by the Rule to have performed the first periodic evaluation. However, the licensee had established plans and procedures for performing these evaluations and had performed two evaluations prior to the inspection. The inspectors reviewed one of these evaluation reports (emergency lighting system) and noted that it appeared to meet the requirements of the Rule. The evaluation noted a declining performance trend with the system's Haloplane batteries. Because the performance of the Haloplane batteries had exceeded the reliability trigger (4 failures in 21 demands) it was categorized as Category (a)(1). The licensee planned to replace the Haloplane batteries with a new design within the next 2 years.

The inspectors also noted that preventive maintenance activities were being adjusted as required by paragraph (a)(3) whenever a goal or performance criteria was exceeded or whenever a structure, system, or component experienced a maintenance preventible functional failure. These ongoing adjustments, in lieu of periodic, was considered a strength of the licensee's program.

c. Conclusions

Plans and procedures for performing the periodic evaluation appeared tc meet the requirements of the Rule.

M1.4 Balancing Reliability and Unavailability

a. Inspection Scope

Paragraph (a)(3) of the Rule requires that adjustments be made, where necessary, to assure that the objective of preventing failures through the performance of preventive maintenance is appropriately balanced against the objective of minimizing unavailability due to monitoring or preventive maintenance. The inspectors reviewed the plans and procedures the licensee had established to ensure this evaluation was completed as required. The inspectors also discussed these plans with the licensee's Maintenance Rule coordinator who was responsible for performing this evaluation.

b. Observations and Findings

The licensee's approach of balancing equipment reliability and unavailability consisted of establishing goals and/or performance criteria for the appropriate structures, systems, and components and then monitoring the performance of the affected equipment. An implicit assumption was made that if appropriate goals and criteria were set, and if such goals and criteria were met, then an appropriate balance between unavailability and reliability would be achieved. The results of the overall process would then be evaluated during the required periodic assessments of maintenance program effectiveness.

The inspectors concluded that such an approach should provide a reasonable balance, provided that appropriate goals and performance criteria were always established. The inspectors noted that the licensee's performance criteria did not always preserve the original probabilistic risk assessment assumptions (see the discussion regarding performance criteria). Thus, while the inspectors determined that the licensee's approach to balancing reliability and unavailability was reasonable, the use of goals and performance criteria that differed from the original probabilistic risk assessment assumptions could limit the effectiveness of this approach.

c. Conclusions

The licensee's approach to balancing reliability and unavailability was reasonable, however, the use of goals and performance criteria that differed from the original probabilistic risk assessment assumptions could limit the effectiveness of this approach.

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

a. Inspection Scope

The inspectors reviewed the licensee's processes for assessing the impact of equipment out-of-service during maintenance activities. Paragraph (a)(3) of the Maintenance Rule states that the total impact on plant safety should be taken into account before taking equipment out-of-service for monitoring or preventive maintenance. The inspectors reviewed the licensee's procedures and discussed the process with the Maintenance Rule coordinator, the expert panel members, operators, and maintenance schedulers.

b. Observations and Findings

The licensee had developed a matrix which identified combinations of equipment allowed to be taken out-of-service simultaneously. Both operators and the work scheduler used this matrix when assessing the safety impact of taking equipment and combinations of equipment out-of-service. Prior to conducting on-line maintenance, an analysis of plant conditions was performed. This analysis included reviews of operational logs to ensure that opposite train equipment or support equipment was not degraded. The results may include decisions to accelerate return-to-service of equipment versus continuation of the equipment out-of-service condition, as scheduled.

The licensee's matrix consisted of various combinations of equipment outages which had been partially pre-analyzed by manipulation of the probabilistic risk assessment model. The matrix also identified configurations not allowed by Technical Specifications. The inspectors determined that the licensee had used their probabilistic risk assessment model to calculate the conditional core damage probability of various systems being out-of-service. The cumulative effect of any two systems being out-of-service was estimated by summing the two conditional core damage probabilities which represented the intersection of the desired configurations (i.e., each axis of the matrix represented a single conditional core damage probability) and then comparing this sum to a predetermined criterion. The comparison represented the relative risk significance of the resulting configuration.

The inspectors noted that there was no analytical basis for the summation of two conditional core damage probabilities. Further, the inspectors concluded that this type of approach would not, in all cases, yield conservative estimates of the true risk associated with a given configuration. In particular, when the two configurations represented at the intersection of the matrix axes were not totally independent, and such an approach could underestimate the risk involved in the configuration. Conversely, when the two configurations were independent, an over estimation of the risk could result. The licensee's representatives agreed that when a dependency existed between the configurations of interest then the approach of summing the conditional core damage probabilities would be nonconservative. The licensee's representatives agreed to review the matrix and ensure that none of the risk estimates, which had been derived by summing the conditional core damage probabilities, were the result of dependent configurations.

In addition to concerns related to the underlying basis of the matrix, the inspectors determined that the licensee's approach to assessing configurations not specifically addressed by the matrix was weak. The licensee's guidance for use of the matrix indicated that if a given configuration was not specifically addressed by the matrix then the new configuration would not represent any additional risk from a nuclear safety standpoint (i.e., note on page 7 of Procedure 30DP-9MTO1, "Assessment of Risk When Performing Maintenance," Revision 3). The inspectors challenged this assertion, and the licensee representatives indicated the procedural guidance may have been misleading. The licensee representatives indicated that maintenance on other (balance-of-plant) systems not governed by the matrix was conducted in accordance with their trip reduction program. Given that few balance-of-plant systems were specifically addressed by the matrix, the inspectors questioned whether the matrix would be of significant value in evaluating relatively high maintenance periods when more equipment was out-of-service than was addressed by the matrix. The licensee's representatives agreed that the matrix would be of limited use in evaluating such configurations. The licensee's representatives stated that further reviews would be conducted to ascertain the risk significance of conducting maintenance activities on systems and configurations which were not addressed by the matrix.

The matrix was used for Modes 1, 2, and, in part, for Mode 3. For the remaining modes of operation, the licensee had established a procedure which followed the guidelines of NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management."

The inspectors concluded that the licensee's method of assessing the impact of equipment out-of-service was generally adequate. However, the weaknesses which were noted could limit the effectiveness of this approach. The lack of comprehensive coverage of balance-of-plant systems (in conjunction with important safety systems) would restrict the range of normal plant maintenance configurations which could be addressed by the matrix. Additionally, even though the inspectors did not explicitly identify a matrix configuration which exhibited a dependency between the two axes (i.e., systems out-of-service), any such dependency could lead to a nonconservative estimate of the risk associated with that particular configuration. The licensee's representatives agreed with the inspectors' observations and conclusions and indicated that improvements would be made to the matrix.

c. Conclusion

The performance of plant safety assessments before taking equipment out-of-service was generally adequate. However, there may be a weakness in the matrix that was used to perform these assessments because some balance-of-plant systems were not modeled in the probabilistic risk assessment.

M1.6 Goal Setting and Monitoring and Preventive Maintenance

a. Inspection Scope

The inspectors reviewed program documents and records in order to evaluate the process that had been established to set goals and monitor under paragraph (a)(1) and to verify that preventive maintenance was effective under paragraph (a)(2) of the Rule. The inspectors also discussed the program with the Maintenance Rule coordinator, system engineers, maintenance engineers, schedulers and operators.

The inspectors reviewed the systems described below to verify: that goals or performance criteria were established with safety taken into consideration; that industry-wide operating experience was considered where practical; that appropriate monitoring and trending was being performed; and, that corrective action was taken when structures, systems, or components failed to meet goal or performance criteria, or when a structure, system, or component experienced a maintenance preventible functional failure.

b. Observations and Findings

b.1 Safety Consideration in Setting Goals and Performance Criteria

The Maintenance Rule as implemented using the guidance in NUMARC 93-01 requires that safety (risk) be taken into consideration when establishing goals under paragraph (a)(1) or performance criteria under paragraph (a)(2).

At the time of the inspection, the licensee had 10 structures, systems, and components in Category (a)(1). The inspectors noted that in addition to placing structures, systems, and components in Category (a)(1) when they had exceeded their performance criteria or experienced maintenance preventible functional failures, the licensee also placed any structures, systems, and component which experienced a functional failure into Category (a)(1). For example, some structures, systems, and components that were in Category (a)(1) were there because of design deficiencies. The inspectors found this to be a conservative approach to implementing the Rule.

The licensee's expert panel used the risk determination process described in Section M1.2 to assess the relative risk of all structures, systems, and components within the scope of the Rule. The results of this process were used to categorize structures, systems, and components as either high risk significant or low risk significant. System or train-level performance criteria were established for all high risk significant systems and those low risk significant systems in standby service except as noted below. Plant-level performance criteria were established for all other structures, systems, and components (i.e., low risk significant normally operating systems).

Additionally, the licensee did not use the run-to-failure or inherently reliable classification of structures, systems, and components; therefore, either goals or performance criteria were established for all structures, systems, and components.

(1) Containment Structure

Based on discussions with engineers within the licensee's maintenance services civil engineering group and review of their procedures, the inspectors determined that the licensee's monitoring program for structures included performing walkdowns of selected zones of structures each year. The engineers stated that all structures were included in the structures monitoring program. The engineers stated that at least a portion of a containment structure would be inspected annually. Aggregation of the samples selected each year would result in a representative sample of all areas of the plant being examined over a 10-year period. Discrepancies identified would be addressed individually under their program. The inspectors found that the licensee had established reasonable schedules for monitoring structures.

The licensee used knowledgeable and experienced civil engineers to perform these structural inspections. This practice was considered by the inspectors to be a strength of their program. However, the inspectors were concerned that the licensee had not identified specific performance criteria to be considered when performing these inspections. The licensee's representatives considered their performance criteria to be all the industry codes and standards which formed the design bases for construction of the plant. The inspectors found that the use of the design basis documents as performance criteria to be impractical because: (1) there are numerous, perhaps hundreds, of specifications in these documents all of which, arguably, could be considered performance criteria; and (2) many of the specifications contained in the design basis documents, such as rebar spacing, can only be verified during construction. The licensee had failed to select specific, appropriate, and verifiable performance criteria from those contained in the design basis and had failed to document them in a structural inspection procedure.

In addition to the use of design bases information instead of specific performance criteria, the licensee's process had no clear guidance for determining when existing preventive maintenance was inadequate and goals needed to be established under paragraph (a)(1) of 10 CFR 50.65. The minutes for the January 4, 1996, expert panel meeting documented that the licensee chose not to establish specific performance criteria or functions for structures. The meeting minutes also documented that a decision to place a structure into Category (a)(1) would be based on an annual review of deficiencies identified. This decision to defer consideration of placing the structure in Category (a)(1) until the annual review is contrary to NUMARC 93-01, which requires the review be done on an ongoing basis.

The inspectors found that the use of design bases information instead of specific performance criteria for structures and the use of unclear guidance for ensuring that structures will be moved to Category (a)(1), when required, were significant weaknesses in the licensee's program for implementing the Maintenance Rule. However, the licensee was effectively monitoring all plant structures and taking actions when problems were identified. At the exit meeting, the licensee stated that they would: establish specific performance criteria within 90 days; and review, and if necessary, revise their procedures to clarify when structures should be moved to Category (a)(1). This issue is an unresolved item pending further NRC review (50-528;529;530/96009-01).

(2) Pressurizer and Reactor Vessel Vent System

Prior to the implementation of the Maintenance Rule, Unit 1 had experienced two instances of performance problems with 1-inch, solenoid-operated valves in the pressurizer and reactor vessel vent system. The inspectors asked if these failures would have been considered functional failures (as indicated in Section M1.6 of this report, the licensee tracked functional failures in lieu of maintenance preventible functional failures), if the Maintenance Rule had been in effect at the time. The licensee representative stated that screening for functional failures would be conducted when reliability and unavailability data were collected and as part of the quarterly failure trend report. The inspectors emphasized to the licensee that functional failures were an important element for moving structures, systems, and components into Category (a)(1) and, therefore, must be identified as part of the root-cause determination process and not wait until the quarterly failure trend report is issued. Licensee representatives stated that they intended to identify additional controls to improve the process of identifying and evaluating maintenance preventible functional failures.

The inspectors found that licensee reviews to identify functional failures for the pressurizer and reactor vessel vent system were not performed in a timely manner.

(3) Steam Bypass Control

The performance criterion for the steam bypass control system was established at the plant level rather than at the system or train level as required for risk significant systems. The inspectors discussed this issue with the system engineer who agreed that the current performance criterion was a plant-level performance criterion. However, the system engineer had not taken credit for other system-level monitoring activities and corrective actions that were performed to resolve the apparently random electronic failures in the steam bypass control system.

The inspectors reviewed these additional monitoring activities and corrective actions and noted that they were the type that were appropriate for monitoring at the system-level under the Maintenance Rule.

The inspectors found that the licensee should have taken credit for those system-level monitoring activities and corrective actions as performance criterion rather than the plant level performance criterion and monitoring.

(4) Feedwater Control System

The licensee placed the feedwater control system in Category (a)(1) due to a decreasing trend in reliability, which the licensee determined to be a design problem. The inspectors reviewed the failure history and noted that most failures of the system had been due to apparently unrelated failures of various electronic components. The corrective actions taken for each of the failures appeared to be reasonable. Despite extensive troubleshooting, the licensee was unable to identify any specific common cause for the failures other than aging. To address the aging issue, the system engineer submitted a proposal to licensee management that the existing analog feedwater control system be replaced with a new digital system.

In the interim period while this proposal was being considered, the expert panel established a Category (a)(1) goal for the feedwater control system of no unplanned scrams due to failures of the feedwater control system, which was the same as the previously established Category (a)(2) plant-level performance criterion. Normally the goals set under Category (a)(1) should be specifically directed at addressing the problem which caused the failures. However, in this case, the licensee had performed extensive tests and monitoring activities, had evaluated industry-wide operating experience, had discussions with the system vendor and other licensees with similar systems, and had not identified any specific cause of the problems other than aging of the analog system. Consequently, the goal that was set appeared to be appropriate.

The inspectors found that the cause determination was thorough and the planned corrective action and goal were appropriate.

(5) Gas Turbines

The licensee placed the gas turbine system in Category (a)(1) due to repeated failures to start during tests. The inspectors reviewed the causes of the start failures with the licensee's representatives and noted that a specific component (air start pressure regulator) had been identified as the cause of most failures. Corrective actions had been taken for the component and start failures had decreased. In addition, specific Category (a)(1) goals were established for the component to assure the problem had been corrected. The licensee was placing appropriate focus on potential multiple recurring failures.

The inspectors also noted that the unavailability goal of 20 percent was not consistent with the probabilistic risk assessment and individual plant evaluation assumptions or recent unavailability data of 0.6 percent. However, an independent review by the inspectors and discussions with licensee staff indicated that an assumed unavailability of 20 percent would not have a significant impact on the probabilistic risk assessment and individual plant evaluation results.

The inspectors found that goals were reasonable and were set commensurate with safety. Corrective actions were also reasonable.

(6) <u>Reactor Coolant Pumps</u>

The licensee had recently placed the reactor coolant system for Unit 1 in Category (a)(1) as a result of performance problems with reactor coolant pump shafts cracking due to fatigue failure. The licensee was collecting pump vibration data and analysis was being conducted to identify any impending pump shaft failure. The planned corrective action was to replace Unit 1 pump shafts that were vulnerable to fatigue failure. In addition, the licensee had been monitoring the unplanned capability loss factor and had set a unit goal of less than 2.7 percent. Loss of capability factor was a plant-level goal and was used because pump shaft replacement prior to a scheduled outage would be reflected in unplanned capability loss factor. Interviews with licensee personnel revealed that the nuclear safety aspects of a catastrophic shaft failure had been considered for goal setting.

The inspectors found that goals were reasonable and set commensurate with safety.

(7) <u>Steam Generator Tubes</u>

The reactor coolant system had also exhibited performance problems related to steam generator tube failures. The licensee had been monitoring tube reliability by inspecting for defects through eddy current data acquisition and analysis. The performance criterion was no tube cracks or defects that would compromise structural integrity. After the tube failure on the Unit 2 steam generator, the licensee decided to place the reactor coolant system in Category (a)(1).

Discussions with licensee personnel indicated that safety (risk) significance was considered in setting the goals for the steam generators. To correct the steam generator tube degradation problems, the licensee had initiated an effort to significantly improve steam generator chemistry, as well as other initiatives. During interviews, licensee personnel expressed confidence that Unit 2 reactor coolant system would be returned to Category (a)(2) in the near future.

The inspectors found that goals were reasonable and set commensurate with safety.

(8) High and Low Pressure Safety Injection

The reliability and unavailability goals for the high and low pressure safety injection systems (low pressure safety injection and high pressure safety injection) were based on the reliability and unavailability assumed in the licensee's probabilistic risk assessment. Separate reliability criteria were established for the shutdown cooling portion of the safety injection system not captured by the goals for the low pressure injection system. The goals and monitoring were appropriate for the systems which were placed under Category (a)(1) due to design deficiencies.

The inspectors found that the goals were reasonable and set commensurate with safety.

(9) Non-Class 1E AC Instrumentation Power

While working on a plant modification to replace the automatic bus transfer device with a faster acting device (discussed below) the licensee had established an interim goal which took safety into consideration.

The inspectors found that the goal was reasonable and set commensurate with safety and that corrective actions were reasonable.

(10) Pressurizer Safety Valves

All three units at Palo Verde had experienced pressurizer safety valve setpoint failures that were identified during outage offsite testing. The licensee's program had established performance criteria by setting a reliability trigger value of 95 percent. Functional failure had been defined as setpoint drift outside the analyzed acceptable setpoint range and test failures versus test attempts were being tracked.

The inspectors found that the performance criteria were reasonable and set commensurate with safety.

(11) Auxiliary Feedwater System

The auxiliary feedwater system was being monitored under Category (a)(2) using train-level performance criteria which were based on probabilistic risk assessment reliability and unavailability. The auxiliary feedwater system had been recently returned to Category (a)(2) after a modification to all three units had significantly increased turbine-driven pump reliability.

The inspectors found that performance criteria were reasonable and were set commensurate with safety.

(12) Emergency Diesel Generators

The emergency diesel generators were being monitored under Category (a)(2) using system or train-level performance criteria which were based on probabilistic risk assessment reliability and unavailability.

The inspectors found that performance criteria were reasonable and were set commensurate with safety.

(13) Charging Pumps

Performance criteria for chemical and volume control charging pumps were based on engineering judgement because charging pump reliability and unavailability had not been explicitly modeled in the probabilistic risk assessment.

The inspectors found that performance criteria were reasonable and set commensurate with safety.

b.2 Use of Industry-Wide Operating Experience

The Maintenance Rule, as implemented using the guidance in NUMARC 93-01, requires that industry-wide operating experience be taken into consideration, where practical, when establishing goals under paragraph (a)(1) or performance criteria under paragraph (a)(2).

Based on review of documentation and discussions with licensee personnel, the inspectors determined that the licensee had established programs for reviewing and evaluating operational experience. NRC information notices, bulletins, and other operating experience information were routinely routed to the system engineers who had the responsibility for establishing performance criteria for their assigned systems.

The inspectors' review of the goals and performance criteria that had been set for the systems indicated that industry operating experience information had been appropriately taken into account when setting performance criteria. In the case of the emergency diesel generator system, the inspectors noted extensive licensee engineering interface with the diesel engine vendor and the owner's group for Cooper-Bessemer engines.

b.3 Monitoring and Trending

The statements of consideration for the Maintenance Rule indicate that, where failures are likely to cause loss of an intended function, monitoring should be predictive in nature and provide early warning of degradation. The licensee had assigned responsibility for trending and evaluating the performance of systems to the system engineers.

The inspectors reviewed the documentation for the selected systems and noted that some predictive monitoring and trending had been performed. Many of the system and train-level performance criteria were based on either the unavailability or reliability data used in the licensee's probabilistic risk assessment. Performance criteria and goals were established by the expert panel and recorded in system bases documents. Where performance criteria for a system or train were exceeded, or where a repetitive failure occurred, the licensee established goals, as required by paragraph (a)(1) of the Rule. The licensee had established "triggers," which were more conservative than the performance criteria. Performance was trended and when performance degraded or exceeded the trigger value, the licensee placed the system in Category (a)(1).

Originally there were five structures, systems, and components in Category (a)(1). At the time of this inspection, there were 10 structures, systems, and components in Category (a)(1). The remainder of the structures, systems, and components are in Category (a)(2). Only one system had moved from Category (a)(1) to (a)(2), namely the auxiliary feedwater system.

The inspectors also noted that the licensee used a centralized data collection group to help ensure uniformity and consistency. This group issued a quarterly failure trend report to identify structure, system, and component performance issues. In addition to collecting failure to start data, this group also collected data on the number of demands for much of the standby equipment. The inspectors noted that the collection of demand data in addition to failure data could considerably improve the licensee's ability to calculate equipment reliability. The inspectors considered this to be a strength of the licensee's program.

b.4 Corrective Actions

The inspectors reviewed the licensee's process and procedures for establishing corrective actions. The inspectors reviewed the corrective actions that were taken for the sample of systems that are listed in Section M1.6 of this report and interviewed each of the maintenance or system engineers who had primary responsibility for performing the root cause determination and establishing the corrective actions. The results of this review for some of those systems are described below.

(1) Non-Class 1E AC Instrumentation Power

The licensee had placed the nonsafety, non-class 1E ac instrumentation power system in Category (a)(1) because the system performance had resulted in reactor trips. Trips had resulted from a loss of power to the feedwater control system when the on-line source of power had been lost due to perturbations in the electrical system. Licensee engineering personnel identified that an automatic bus transfer device had not transferred to the alternate power source quickly enough to prevent the feedwater system from tripping. Additional cause determination and evaluation identified that the automatic bus transfer was designed to transfer to another stable power source within 500 milliseconds.

This was too slow to sustain the operation of the feedwater system, which required the transfer to be completed within 120 milliseconds. Engineering personnel developed a modification to install a faster acting automatic bus transfer. In the interim, the system lineup was changed to use the most reliable source as the normal source, and the frequency of preventive maintenance was increased. The system had been assigned a goal of less than two reactor trips in 18 months for each unit. According to engineering personnel this goal was sufficient to monitor system performance until such time as a generic modification was in place for all three units.

The inspectors found that the licensee had considered safety in the establishment of monitoring and goals. The licensee had in place an excellent process for the root cause evaluation. Corrective actions were appropriate. Maintenance and system engineers were very knowledgeable of their assigned systems and were proactive in the development and implementation of corrective actions.

(2) Pressurizer and Reactor Vessel Vent System

Unit 1 had experienced two instances of performance problems with 1-inch, solenoid-operated valves in the pressurizer and reactor vessel vent system. The first event occurred at power in November 1994 when two valves in series, RC-103 and 105, began cycling independently without a demand signal. The unit eventually had to be shutdown for a 5-day outage to refurbish the valves. During the most recent outage in April 1996, another system valve, RC-108, would not close on demand until the system lineup was changed to develop a differential pressure across the valve. The valve was refurbished and, subsequently, operated successfully. The licensee planned to refurbish all 21 valves, 7 per unit, on a three-outage basis. All valves in all three units were to be completed in 54 months.

The inspectors found that the root cause evaluation and corrective action were appropriate.

(3) Condenser

When a reactor trip was attributed to the loss of condenser vacuum due to a solenoid valve leaking air, the cause was determined to be aging of the internal gaskets of the valve body. Using a conservative valve lifetime, the licensee planned to replace the valve every 6 years even though the valve's use was expected to be acceptable for about 9 years.

The inspectors found that the root cause evaluation and corrective action were appropriate.

(4) Safety Injection

The inspectors' review of three problems associated with the low pressure safety injection and the high pressure safety injection portions of the safety injection system indicated that the root cause evaluations and planned corrective actions were appropriate.

c. Conclusions

c.1 Safety Consideration in Setting Goals and Performance Criteria

Reasonable goals or performance criteria that took safety into consideration were set for the feedwater control system, gas turbines, reactor coolant pumps, steam generator tubes, high and low pressure safety injection systems, Non-Class 1E ac instrumentation power, pressurizer safety valves, auxiliary feedwater system, emergency diesel generators, and the chemical and volume control charging pumps.

The following exceptions were noted:

- The failure to establish any performance criteria for the shutdown cooling portion of the safety injection system was a violation of 10 CFR 50.65.

- The selected performance criteria for the containment and other structures and the lack of clear guidance for placing structures, systems, and components in Category (a)(1) or (a)(2) was a weakness and an unresolved item (50-528;529;530/9609-02).

- The use of a quarterly failure trend data collection report to identify functional failures for the pressurizer and reactor vessel and vent system was a weakness.

- The selected plant-level performance criteria and monitoring for the steam bypass control system that did not take credit for the ongoing system-level monitoring and corrective actions was a weakness.

c.2 Industry-Wide Operating Experience

Industry-wide operating experience had been appropriately taken into consideration when setting goals and performance criteria.

c.3 Monitoring and Trending

Predictive monitoring and trending of appropriate parameters was being performed. The use of a centralized data collection group (to help ensure consistency) and the collection of demand data (in addition to failure data) were considered strengths of the licensee's program.

c.4 Conclusions for Corrective Actions

Root-cause analysis and corrective actions appeared to be a strength of the licensee's maintenance program. Maintenance and system engineers were very knowledgeable of their assigned systems and proactive in the development and implementation of corrective actions related to their systems.

M2 Maintenance and Material Condition of Facilities and Equipment

a. Inspection Scope

In the course of verifying the implementation of the Maintenance Rule using NRC Inspection Procedure 62706, the inspectors performed walkdowns to examine the material condition of the following systems:

- Essential chilled water,
- Containment hydrogen control,
- Condensate,
- Safety injection system pump rooms,
- Emergency diesel generators,
- Gas turbines,
- Feedwater control system,
- Class 1E 125 volt dc power,
- Steam bypass control, and
- Non-class 1E instrument power.

b. Observations and Findings

The inspectors found that the systems inspected appeared to be free of corrosion; oil leaks; water leaks; tra[illegible] and based on their external condition, well maintained. The gas turbines appeared to be particularly well maintained. However, identification and corrective action for small leaks on components could be improved. One example identified by the inspectors was a small leak on a fuel line on one of the Unit 2 emergency diesel generator day tank rooms.

c. Conclusions

In general, the material condition of the selected systems examined during the inspection was satisfactory. The material condition of the gas turbines was very good.

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self Assessment

a. Inspection Scope

The inspectors reviewed the licensee's Audit Report 96-020, "Integrated Self-Assessment of PVNGS Maintenance Rule Program," dated May 31, 1996.

b. Observations and Findings

The audit was comprehensive and identified both good performance areas and areas in need of management attention. Several areas in need of attention were obvious to the inspectors during this inspection. Examples were personnel, other than middle managers, not being aware of their specific roles and responsibilities with regards to the Maintenance Rule. This was noted during interviews with both engineering and operations personnel. All findings were entered into the licensee's corrective action program for appropriate disposition and several corrective actions had been implemented.

c. Conclusions

The inspectors concluded the audit scope was comprehensive, and provided meaningful feedback to management.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.3 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

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

E4 Engineering Staff Knowledge and Performance

E4.1 Engineers Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The inspectors interviewed licensee engineers within both the nuclear engineering and maintenance organizations to assess their understanding of the Maintenance Rule and associated responsibilities.

b. Observations and Findings

All maintenance and system engineers interviewed were very knowledgeable of their assigned systems and demonstrated sufficient knowledge to adequately implement their responsibilities under the Maintenance Rule. However, weaknesses among the engineering staffs were identified during interviews in the following areas:

- Understanding of what constituted a functional failure. One engineering supervisor incorrectly believed that a functional failure could only result from a failure on demand. In addition, the supervisor incorrectly believed that a spurious actuation of a ground fault relay which caused a low pressure safety injection valve to be inoperable would not be considered a functional failure under the Maintenance Rule. One system engineer did not recognize that failures caused by human actions could be considered functional failures under the Maintenance Rule. These misunderstandings of what constituted a functional failure were resolved by the end of the inspection. The inspectors did not identify any examples of a functional failure which had been misclassified.

- Understanding of how the performance criteria for systems were developed. Some system engineers did not have a clear understanding of how performance criteria for their systems were developed and how probabilistic risk assessment was used in the process.

- Understanding of engineering staff responsibilities in participating in the expert panel discussions. Most engineers did not recognize that they were a voting member of the expert panel in regards to structures, systems, and components for which they were responsible.

The issue of training was discussed with licensee management representatives. Previously the expert panel was primarily responsible for establishing performance criteria for each system. Recently the role of the maintenance and system engineers in the Maintenance Rule process had been expanded and training in the form of a self-study course was underway for many of the engineering staff.

c. Conclusions

All maintenance and system engineers interviewed were very knowledgeable of their assigned systems and demonstrated sufficient knowledge to adequately implement their responsibilities under the Maintenance Rule. However, some weaknesses in their knowledge of certain aspects of the Maintenance Rule and were noted.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors discussed the progress of the inspection with licensee representatives on a daily basis and presented the inspection results to members of licensee management at the conclusion of the inspection on July 19, 1996. In addition, a supplemental telephonic exit was held on August 16, 1996, to discuss the enforcement findings from the inspection. 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.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

LICENSEE:

J. Bailey, Vice President
S. Bauer, Licensing Section Leader
S. Boardman, Maintenance Rule Project Manager
G. Box, Training Section Leader
P. Brandses, Department Leader, Maintenance
W. Ide, Director, Operations
J. Levine, Vice President
R. Lucero, Department Leader, Maintenance
D. Mauldon, Director, Maintenance
G. Overbeck, Vice President

NRC:

S. Black, Branch Chief
D. Carter, Resident Inspector
R. Frahm Jr., Reactor Engineer
D. Garcia, Resident Inspector
T. Gwynn, Director
D. Kelly, Contractor
J. Kramer, Resident Inspector
C. Petrone, Senior Reactor Engineer
W. Scott Jr., Sr. Reactor Engineer
J. Shackelford, Reliability & Risk Analyst
F. Talbot, Reactor Engineer
D. Taylor, Reactor Inspector
S. Tingen, Reactor Engineer
J. Wilcox Jr., Senior Operations Engineer

LIST OF INSPECTION PROCEDURES USED

IP 62706 Maintenance Rule

LIST OF ITEMS OPENED

Opened

50-528;529;530/96009-01	URI	Performance criteria for the containment and other structures and guidance for placing structures, systems, and components in the Category (a)(1) and (a)(2). (Section M1.6.b.1(2)).

ATTACHMENT 2

LIST OF PROCEDURES REVIEWED

30DP-0MR01, "Maintenance Rule," Revision 0, May 24, 1996

71DP-0EM01, "Risk Management Program Expert Panel," Revision 0, May 24, 1996

13-NS-C09, "Maintenance Rule Scoping Study, Not Applicable (NA)," May 22, 1996

71IG-0EP01, "System-Level Risk Ranking Level," Revision 0, May 29, 1996

13-NS-C14, "Risk Significant Determination for Implementation of the Maintenance Rule," Revision NA, June 12, 1996

81DP-0ZZ01, "Civil Component Performance/Condition Monitoring," Revision 2, May 14, 1996

30IG-0MR01, "Performance Monitoring Instruction," Revision 0, May 24, 1996

70DP-0EE01, "Equipment Root Cause of Failure Analysis," Revision 6, May 31, 1996

73AC-0RA01, "Failure Data Trending and Nuclear Plant Reliability Data System," Revision 5, June 7, 1996

71IG-0EP02, "(a)(2) to (a)(1) Dispositioning and Goal Setting," Revision 0, June 11, 1996

30DP-9MP08, "Preventive Maintenance Basis Development," Revision 5, September 29, 1994

30DP-9MT01, "Assessment of Risk When Performing Maintenance," Revision 3, June 12, 1996

73ST-IZZ12, "Settlement Monitoring Program," Revision 1, June 23, 1995

71IG-0EP03, "Methodology Used By PRA Group/Expert Panel to Develop Unavailability and Reliability Performance Criteria For Systems, Trains and Components," Revision 0, June 12, 1996

13-NS-C23, "PRA (LERF) Risk Ranking Information for Maintenance Rule System Risk Ranking," Revision NA, April 9, 1996

13-NS-C08, "PRA of Transition Risk (Forced Shutdown)," Revision NA, March 20, 1996

13-NS-C13, "PRA (CDF) Risk Ranking Information for Maintenance Rule System Risk Ranking," Revision NA, May 16, 1996

13-NS-B39, "Safety Significance Analysis of Work During Maintenance Outage Windows," Revision NA November 1, 1995

90DP-0IP02, "Nuclear Administrative and Technical Manual, Investigation Methods," Revision 2, June 1989

NRC INFORMATION NOTICES

89-01	VALVE BODY EROSION
89-30	SUPPLEMENT 1: HIGH TEMPERATURE ENVIRONMENTS AT NUCLEAR POWER PLANTS
89-43	PERMANENT DEFORMATION OF TORQUE SWITCH HELICAL SPRINGS LIMITORQUE SMA-TYPE MOTOR OPERATORS
89-61	FAILURE OF BORG-WARNER GATE VALVES TO CLOSE AGAINST DIFFERENTIAL PRESSURE
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92-41	CONSIDERATION OF THE STEM REJECTION LOAD IN CALCULATION OF REQUIRED VALVE THRUST
92-56	COUNTERFEIT VALVES IN THE COMMERCIAL GRADE SUPPLY SYSTEM
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93-01	ACCURACY OF MOTOR-OPERATED VALVE DIAGNOSTIC EQUIPMENT MANUFACTURED BY LIBERTY TECHNOLOGIES
93-37	EYEBOLTS WITH INDETERMINATE PROPERTIES INSTALLED IN LIMITORQUE VALVE OPERATOR HOUSING COVERS
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93-74	HIGH TEMPERATURES REDUCE LIMITORQUE AC MOTOR OPERATOR TORQUE
93-88	STATUS OF MOTOR-OPERATED VALVE PERFORMANCE PREDICTION PROGRAM BY THE ELECTRIC POWER RESEARCH INSTITUTE
93-90	UNISOLATABLE REACTOR COOLANT SYSTEM LEAK FOLLOWING REPEATED APPLICATIONS OF LEAK SEALANT
93-97	FAILURES OF YOKES INSTALLED ON WALWORTH GATE AND GLOBE VALVES
93-98	MOTOR BRAKES ON VALVE ACTUATOR MOTORS
94-10	FAILURE OF MOTOR-OPERATED VALVE ELECTRIC POWER TRAIN DUE TO SHEARED OR DISLODGED MOTOR PINION GEAR KEY
94-18	ACCURACY OF MOTOR-OPERATED VALVE DIAGNOSTIC EQUIPMENT (RESPONSES TO SUPPLEMENT 5 TO GL 89-10)
94-30	LEAKING SHUTDOWN COOLING ISOLATION VALVES AT COOPER NUCLEAR STATION
94-49	FAILURE OF TORQUE SWITCH ROLL PINS
94-50	FAILURE OF GENERAL ELECTRIC CONTACTORS TO PULL IN AT THE REQUIRED VOLTAGE

94-55 PROBLEMS WITH COPES-VULCAN PRESSURIZER POWER-OPERATED RELIEF VALVES

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94-67 PROBLEMS WITH HENRY PRATT MOTOR-OPERATED BUTTERFLY VALVES

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TAB D

PLANT/STAFF DATA - SITE MAP - SALP -SIM

Table 2-3. General Plant Data - Sorted by NSSS Vendor and A-E

Reactor Type	NSSS Vendor	Architect/ Engineer	Reactor Plant	Core Power MWt	Net Electrical Output MWe	MWe Rating MDC or DER	City	State	Utility
PWR	B&W	Bechtel	ANO-1	2568	836	MDC	Russellville	AR	Arkansas Power & Light Co.
PWR	B&W	Bechtel	Davis-Besse	2772	860	MDC	Oak Harbor	OH	Toledo Edison Co.
PWR	B&W	Bechtel	Rancho Seco	2772	873	MDC	Clay Station	CA	Sacramento Municipal Utility District
PWR	B&W	Duke/ Bechtel	Oconee 1	2568	846	MDC	Seneca	SC	Duke Power Co.
PWR	B&W	Duke/ Bechtel	Oconee 2	2568	846	MDC	Seneca	SC	Duke Power Co.
PWR	B&W	Duke/ Bechtel	Oconee 3	2568	846	MDC	Seneca	SC	Duke Power Co.
PWR	B&W	Gilbert	Crystal River 3	2544	821	MDC	Red Level	FL	Florida Power Corp.
PWR	B&W	Gilbert	Three Mile Island 1	2535	776	MDC	Londonderry Twp	PA	GPU Nuclear Corp.
PWR	B&W	TVA	Bellefonte 1	3413	1213	DER	Scottsboro	AL	Tennessee Valley Authority
PWR	B&W	TVA	Bellefonte 2	3413	1213	DER	Scottsboro	AL	Tennessee Valley Authority
PWR	B&W	UE&C	WNP-1	3760	1266	DER	Richland	WA	Washington Public Power Supply System
PWR	C-E	Bechtel	ANO-2	2815	858	MDC	Russellville	AR	Arkansas Power & Light Co.
PWR	C-E	Bechtel	Calvert Cliffs 1	2700	825	MDC	Lusby	MD	Baltimore Gas & Electric Co.
PWR	C-E	Bechtel	Calvert Cliffs 2	2700	825	MDC	Lusby	MD	Baltimore Gas & Electric Co.
PWR	C-E	Bechtel	Millstone 2	2700	863	MDC	Waterford	CT	Northeast Utilities
PWR	C-E	Bechtel	Palisades	2530	730	MDC	South Haven	MI	Consumers Power Co.
PWR	C-E	Bechtel	Palo Verde 1	3800	1221	MDC	Wintersburg	AZ	Arizona Public Service Co.
PWR	C-E	Bechtel	Palo Verde 2	3800	1221	MDC	Wintersburg	AZ	Arizona Public Service Co.
PWR	C-E	Bechtel	Palo Verde 3	3800	1221	MDC	Wintersburg	AZ	Arizona Public Service Co.
PWR	C-E	Bechtel	San Onofre 2	3390	1070	MDC	San Clemente	CA	Southern California Edison/San Diego Gas & Electric
PWR	C-E	Bechtel	San Onofre 3	3390	1080	MDC	San Clemente	CA	Southern California Edison/San Diego Gas & Electric
PWR	C-E	Ebasco	St. Lucie 1	2700	839	MDC	Hutchinson Island	FL	Florida Power & Light Co.
PWR	C-E	Ebasco	St. Lucie 2	2700	839	MDC	Hutchinson Island	FL	Florida Power & Light Co.

PART 1 - FACILITY DESCRIPTION

1.1 FACILITY/LICENSEE

FACILITY: St. Lucie Units 1 and 2
PLANT LOCATION: Hutchinson Island near Port St. Lucie, Florida
LICENSEE: Florida Power and Light Co. (Corporate Office in Juno Beach, Florida)

1.2 UTILITY SENIOR MANAGEMENT

CORPORATE:

J. L. Broadhead (Jim), Chairman of the Board and CEO
T. F. Plunkett (Tom), President, Nuclear Division

SITE:

J. A. Stall (Art) - St. Lucie Plant Vice President
C. L. Burton (Chris) - Services Manager
L. W. Bladow (Wes) - Nuclear Assurance Manager
R. E. Dawson (Bob) - Business Manager
D. J. Denver (Dan) - Site Engineering Manager
L. Morgan (Lynn) - Human Resources Manager
M. H. Allen (Mike) - Training Manager
J. Marchese (Joe) - Maintenance Manager
C. H. Wood (Chuck) - Work Control Manager
J. Scarola (Jim) - Plant General Manager
E. J. Weinkam III (Ed) - Licensing Manager
H. Johnson (Hugh) - Operations Manager

1.3 NRC STAFF

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NRR:

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L. A. Wiens (Len), Senior Project Manager, Project Directorate II-2, (301) 504-1495

AEOD:

S. Israel (Sandy), Reactor Operations Analysis Branch, (301) 415-7573

1.4 LICENSE INFORMATION

	Unit 1	Unit 2
Docket Nos.	50-335	50-389
License Nos.	DPR-67	NPF-16
Construction Permit Nos.	CPPR-74	CPPR-144
Construction Permit Issued	7/1/70	5/2/77
Low Power License	NA	4/83
Full Power License	3/1/76	6/10/83
Initial Criticality	4/22/76	6/2/83
1st Online	5/17/76	6/13/83
Commercial Operation	12/21/76	8/8/83

1.5 PLANT CHARACTERISTICS

Description	Units 1 and 2
Reactor Type	Combustion Engineering PWR, 2-loop
Containment Type	Freestanding Steel w/Shield Building
Power Level	830 MWe (2700 MWt)
Architect/Engineer	Ebasco
NSSS Vendor	Combustion Engineering
Constructor	Ebasco
Turbine Supplier	Westinghouse
Condenser Cooling Method	Once Through
Condenser Cooling Water	Seawater

1.6 SIGNIFICANT DESIGN INFORMATION

1.6.1 REACTOR INTEGRITY

Reactor Pressure Vessel (RPV)

With the present fuel type and management policy, Unit 1 is expected to reach a 40-year RPV life. On this unit, the fuel type and management policy have been modified to make that RPV life span possible. Presently, a program is evolving for RPV life extension beyond the projected 40 years, potentially to 60 years, via a flux reduction program. A flux reduction program has started with the addition of eight absorbers in core corner positions, performance of vessel fluence calculations, and determination of an optimum power profile for each core load. Calculations using current methodology and uncertainty predict a significant RPV life extension, but not to 60 years.

Due to different design and construction characteristics, Unit 2 RPV life expectancy exceeds 60 years. Low leakage core designs are now used for economic reasons, however the low leakage designs provide even greater life expectancy.

Reactor Coolant Pressure Boundary

On this CE plant, ECCS-to-RCS injection points are isolated by at least two check valves and one closed MOV. High pressure safety injection (HPSI), low pressure safety injection (LPSI), and containment spray (CS) pumps' common containment sump suctions are isolated from the containment sump by one closed MOV in conjunction with a closed seismic piping system. The CS headers are isolated from containment by one closed MOV and a check valve in conjunction with a closed seismic piping system. CVCS has the normal complement of two automatic actuation isolation valves.

1.6.2 REACTOR SHUTDOWN

Reactor Protection System

The reactor protection system provides protection for the reactor fuel and its cladding by providing automatic reactor shutdowns based on input from reactor power, reactor coolant pressure, coolant temperature, coolant flow, steam generator pressure, containment pressure, turbine hydraulic fluid pressure, and, in Unit 2 only, Component Cooling Water flow to reactor coolant pumps. The RPS is a redundant, four channel system that operates on a two-out-of-four logic.

ATWS Protection

ATWS protection, outside the normal reactor protection system, is initiated via the ESF pressurizer pressure signal. It actuates by opening contactors in the output of the CEA MG sets, thereby interrupting control element assembly power at its source. This protection has been installed on both units per CE, the NSSS, recommendations.

Remote Shutdown Facilities

These facilities are located in the switchgear rooms beneath each unit's control room.

1.6.3 CORE COOLING

Feedwater System

The main feedwater pumps are motor driven with each delivering 50 percent of the flow required for full power.

Turbine Bypass/Steam Dump Capacity

Each unit has five steam bypass valves, providing 45 percent of total capacity.

Unit 1 has one atmospheric dump valve per train (two trains) and Unit 2 has two valves per train. Each unit has the capability of dumping nine percent steam flow to the atmosphere.

Auxiliary Feedwater System

There are two motor-driven pumps on each unit with 100 percent capacity per pump. There is one steam-driven pump on each unit with 200 percent capacity. Any of the three pumps can inject to either steam generator. Automatic initiation and faulted steam generator protection are provided by each unit's Auxiliary Feedwater Actuation System provided by the NSSS.

Emergency Core Cooling System

In each unit, there are two HPSI pumps and two LPSI pumps with no unit-to-unit cross-connections. One pump of each type per unit will handle a postulated LOCA. The LPSI pumps also provide decay heat removal as required when the unit is shut down.

Decay Heat Removal

As indicated above, the LPSI pumps also provide decay heat removal as required when the unit is shut down by taking suction from the RCS (hot legs), passing the fluid through the shutdown cooling heat exchangers, and returning it to the RCS (cold legs). The heat removing medium is CCW - discussed in section 1.7.6 below. Shutdown cooling flow path overpressure protection is provided by automatic isolation valves and various relief valves in the system.

1.6.4 CONTAINMENT

Pressure Control/Heat Removal

There are two containment spray pumps and four containment fan coolers available per unit to suppress pressure spikes and cool the containment. One CS pump and two fan coolers will handle a postulated LOCA. There are no unit-to-unit cross-connections. This engineered safety feature is automatically started by ESFAS.

Hydrogen Control

Post-LOCA containment hydrogen control is accomplished on each unit by two trains of hydrogen recombiners located on the operating deck inside containment. By elevating, in a controlled manner, the temperature of containment atmosphere flowing through the recombiner, the recombiner units recombine hydrogen and oxygen to form water, thus preventing the buildup of hydrogen to potentially explosive levels.

1.6.5 ELECTRICAL POWER

Offsite AC

The station switchyard is connected to the transmission system by three independent 240 KV lines that share a right of way and interconnect with FPL's grid on the mainland approximately 10 miles West of the plant site. There are two independent offsite power feeds from the station switchyard to the emergency busses.

Onsite AC

Onsite AC power is provided by four EDGs (two per unit). EDGs are independent of other plant systems except vital DC power for control of starting. A Station Blackout (SBO) cross connection is installed and tested. This cross-connection serves the emergency busses directly and reduces cross-connect time to less than 15 minutes.

DC Power

Two trains of vital batteries per unit have been routinely tested for four-hour DC load profiles. Recently, following a cell replacement, they have been tested for three-hour battery capacity instead. The battery capacity test is harsher than the load profile test and is intended to more accurately reflect expected usage. There are four normal chargers per unit with swing chargers available for service. Non-safety batteries can be cross-connected to the safety-related swing bus if needed.

Instrumentation Power

Each unit has four inverters, two powered from each vital DC train, that provide four trains of instrumentation power.

Station Blackout Resolution Status

Unit 2 is a four-hour "DC coping" plant per the original license while Unit 1 is subject to the station blackout (SBO) rule of 10 CFR 50.63 requiring additional licensee action (unit-to-unit cross-connect of 4160V bus).

1.6.6 SAFETY-RELATED COOLING WATER SYSTEMS

Intake Cooling Water (Service Water)

Intake cooling water (ICW) for each unit originates in the unit-common Intake Canal. The canal level varies with the tides since it is filled by a level difference between the Atlantic Ocean and the ICW pumps. One 16-foot and two 12-foot diameter pipes pass under the beach to connect the ocean and canal. The intake pipe ends in the Atlantic are covered by intake structures (rebuilt in 1991) intended to limit flow velocities, particularly vertical velocity, to reduce marine life entrapment. After use, ICW returns to the ocean through the Discharge Canal and under-beach pipes.

Each unit has two trains of ICW plus a swing pump that can be aligned to either train electrically and physically. The licensee has converted the deep draft ICW pumps from externally (water) lubricated to self-lubricated to increase reliability. The 100 percent (each) capacity pumps take suction from the intake canal via a canal intake structure using traveling screen debris protection. The intake canal structures adjacent to the ICW pump suctions are continuously injected with a hypochlorite solution to reduce marine growth in the associated piping and heat exchangers.

The ICW pumps move water through two trains of heat exchangers that cool component cooling water (CCW) and two trains of heat exchangers that cool main turbine cooling water. During a postulated accident, water flow isolates from the turbine cooling heat exchangers. The discharge from the heat exchangers returns via the discharge canal to the ocean.

Closed Cooling Water Systems

Each unit has two trains of Component Cooling Water (CCW). The arrangement of two pumps and a swing pump mimics the ICW system. The swing pump can be aligned to either train. The 100 percent (each) capacity pumps drive water through the CCW/ICW heat exchangers and then on to the heat loads, mainly the containment fan coolers and the shutdown cooling (decay heat) heat exchangers (which also can operate as containment spray heat exchangers). Additionally, CCW cools a variety of bearings, seals, and oil coolers for the HPSI, LPSI, and CS pumps. A non-safety-related portion of the CCW system cools reactor coolant pump seals and the spent fuel pool. This section isolates upon engineered safety features actuation.

1.6.7 SPENT FUEL STORAGE

Wet storage capability exists up to the year 2002 (Unit 2) and 2007 (Unit 1).

1.6.8 INSTRUMENT AIR SYSTEM

Instrument air compressors and driers on each unit provide all instrument air for Unit 2 and all but containment air for Unit 1. Unit 1 has instrument air compressors inside containment.

1.6.9 STEAM GENERATORS

Each unit has two large steam generators (SGs) rather than the three or four usually seen. The licensee is focusing on a Unit 1 SG replacement in 1998. The SGs are under construction at the B&W Canada shops and a site organization is functioning.

1.7 EMERGENCY RESPONSE FACILITIES/PREPAREDNESS

Emergency Operations Facility:	10 miles West of site, I-95/Midway Rd. Exit
Technical Support Center:	Onsite, Adjacent to Unit 1 Control Room
Operational Support Center:	Onsite, 2nd floor of North Service Building

The last annual emergency preparedness exercise was in February, 1996. This exercise was formally evaluated by the NRC.

Since St. Lucie site has a high probability of hurricanes, communications facilities were improved following the Turkey Point experience with Hurricane Andrew in August, 1992. Improvements include:

- High Frequency Auto-link with other FPL sites and NRC.
- Enhanced 900 MHZ System for site and mobile communications, with radios also in the licensee's EOF and county emergency facility.
- Cellular phones with hardened antennas.
- Hardened Local Government Radio antenna ties.

1.8 PRESENT OPERATIONAL STATUS

Availability Factors:

	Unit 1	Unit 2
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994	86.8	79.6
1995	76.1	75.0
Cumulative (through 7/95)	57.6	93.4

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months from 8/1/96)

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. Due to a series of equipment problems and personnel performance issues, the unit remained shut down for 73 days. Problems encountered during the shutdown included a maintenance-induced RCP seal failure, discovery of two inoperable PORVs due to maintenance errors during refurbishment, a loss of inventory event while placing shutdown cooling in service due to lack of margin to relief valve lift setpoint and complicated by an excessive blowdown value, inadvertant spraydown of the Unit 1 containment, catastrophic failure of the 1B EDG, and leaking pressurizure code safety valve flange leakage. The unit returned to power on October 12.

On November 16, the unit was manually tripped when a feedwater regulating valve failed to the 50% position, resulting in low steam generator water level. The root cause of the failure was determined to be a faulty power supply. The power supply was replaced and the unit was returned to service on November 18.

On January 22, 1996, operator error resulted in an excessive dilution event which resulted in reactor power accending to 100.2%. The operator in question apparently left the control room while dilution was in progress without informing other watchstanders of the evolution in progress. The operator was removed from licensed duties and the final disposition of the event is pending.

On January 22, 2996, a failed power supply resulted in a dropped CEA, a declaration of a Notification of Unusual Event and a unit shutdown. While downpowering the unit, the failure of a feedwater regulating valve lead to difficulties in controling steam generator water level and a resultant manual reactor trip.

on April 28, 1996, Unit 1 was taken off line for a refueling outage. The outage lasted until July 23. During the outage, excessive steam generator tube plugging projections resulted in the need for TS ammendments to accomodate plugging in excess of accident analysis assumptions (25%). Actual plugging was approximately 24%.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months from 8/1/96)

Unit 2 operated continuously during the past 12 months with the following exceptions:

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. It was restarted on August 4, 1995, but operated at reduced power from August 17 through 29, 1995, to clean condenser water boxes and repair equipment problems.

On October 9, the unit entered a refueling outage. The outage was complicated by the discovery of leaks in RCS flow transmitter taps at the loops, a reactor flange O-ring leak, discovered during repressurization, and the failure of one stage of an RCP seal package. The unit returned to power on January 1, 1996.

The unit was manually tripped from approximately 35% power on January 5 due to high generator hydrogen temperature. The root cause of the event was improper operation of a turbine cooling water temperature control valve which supplied cooling water to the hydrogen coolers. Post-trip review resulted in the discovery of clogged steam generator water level transmitter sensing lines which resulted in artificially low levels being indicated when steam generators were isolated upon turbine trip. The lines were blown down and the unit was returned to service on January 7.

On March 31, 1996, a Notification of Unusual Event was made as a result of unidentified RCS leakage of greater than 1 gpm. The cause was determined to be leakage past a CVCS system relief valve.

On April 20, the unit was downpowered and taken off line due to low turbine auto stop oil pressure following turbine trip testing. The cause was determined to be blockage in a flow control orifice which prevented adequate makeup oil to the sensed header.

On June 6, 1996, operators manually tripped the unit as a result of high main generator gas temperature. The cause was a failure in a turbine cooling water flow control valve to the hydrogen coolers which resulted in a starvation of cooling water to the coolers.

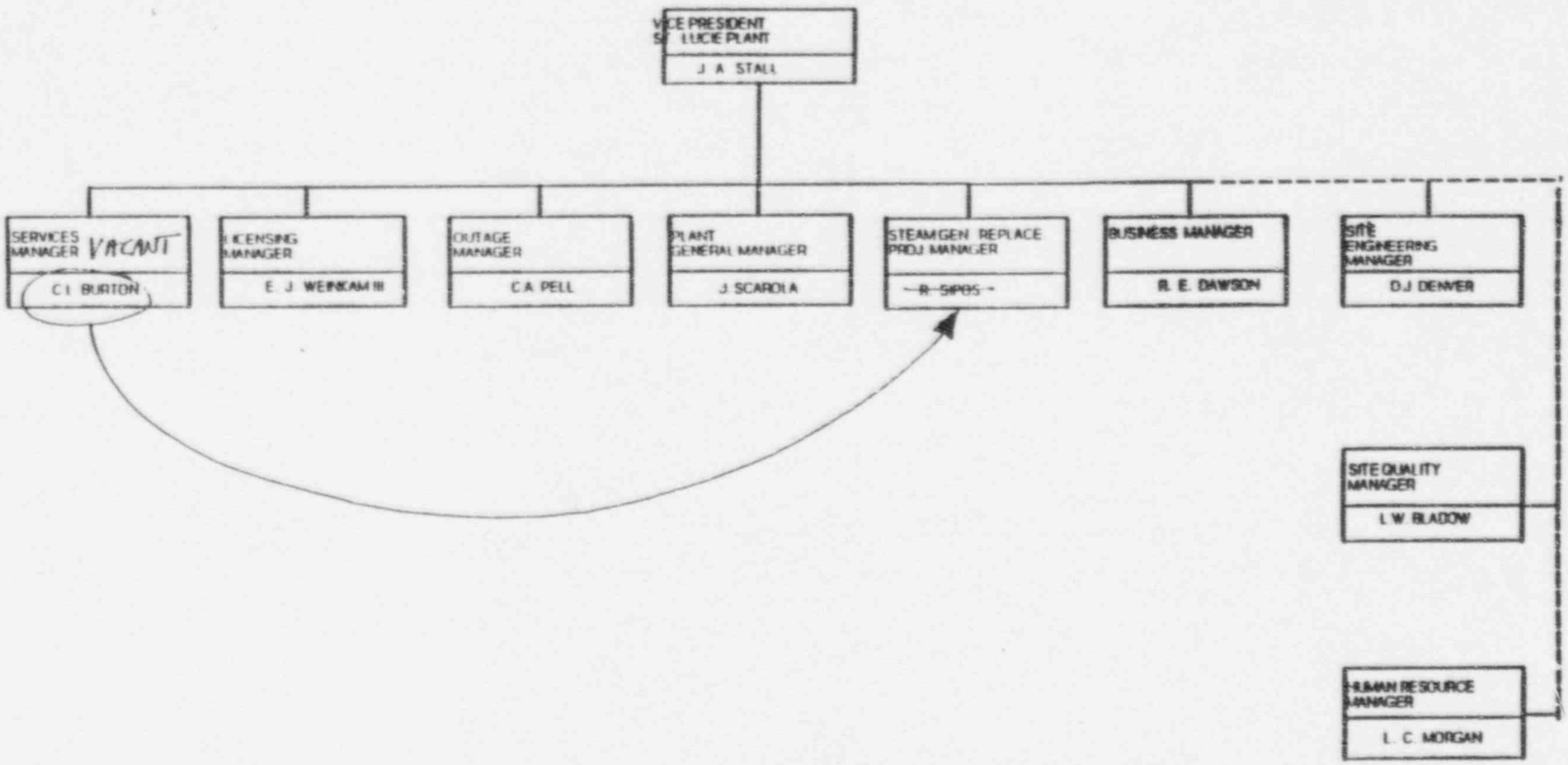
On August 9, a Notification of Unusual Event was made due to unidentified RCS leakage in excess of 1 gpm. The source of the leakage was determined to be a charging pump packing leak.

1.9 OUTAGE SCHEDULE AND STATUS

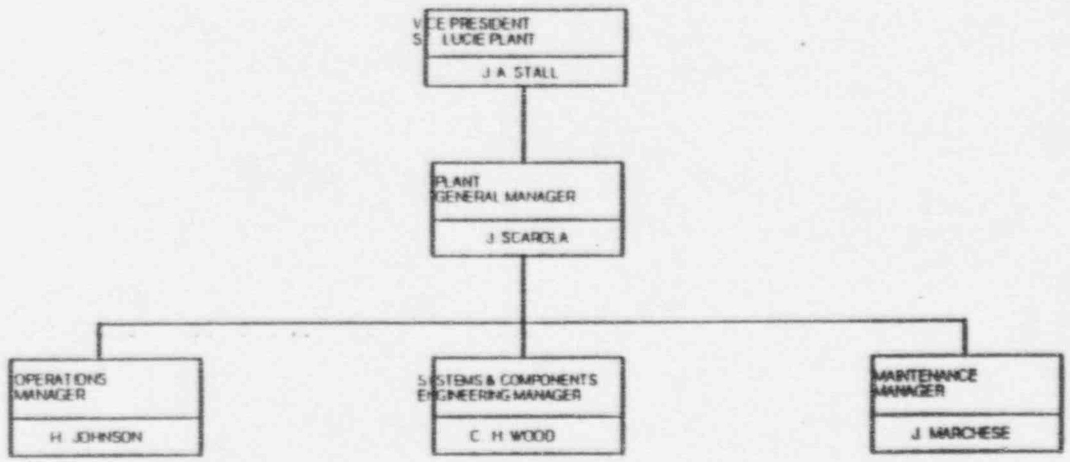
Unit 1's last refueling outage began on April 28, 1996, and ended on July 23. Major activities included: refueling; reactor vessel ISI inspection; integrated safeguards test; steam generator tube inspection and plugging; several instances of reduced inventory/ mid-loop operations; replacement of EDG radiators; inspection of ECCS sump area; and mechanical, electrical, and I&C systems maintenance. The next Unit 1 refueling outage is scheduled for Fall, 1997.

Unit 2's last refueling outage began on October 9, 1995, and ended January 1, 1996. Major outage activities included: refueling; steam generator tube inspection and plugging; low pressure turbine blade replacement; emergency diesel generator inspection; replacement of three reactor coolant pump mechanical seals; and mechanical, electrical, and

ST. LUCIE NUCLEAR PLANT
ORGANIZATION CHART
PSL MANAGEMENT
JUNE 12, 1998



ST. LUCIE NUCLEAR PLANT
ORGANIZATION CHART
SITE OPERATING
RESPONSIBILITIES
JUNE 12, 1996



AUGUST 21, 1996 — REGION II RESIDENT ADDRESS LIST

MAILING ADDRESSES	DOC./LIC. NOS.	PHONE/FAX NOS.	RESIDENT INSPECTORS & THEIR ASSIGNMENT DATES	PROJ. ENG.	[illegible]	[illegible]
BABCOCK & WILCOX PO BOX 785 LYNCHBURG VA 24505-0785	B&W NKPD 70-27 SNM-42	804/847-7343 FAX/847-7504	C. ?ayhey, SRI - 02/18/96 *Sherry Burke, Secretary	G. Troup Ext. 15586	E. McAlpine Ext. 15547	E. Flack 415-2405 NMSS
'WNS FERRY 33 SHAW RD .HENS AL 35611	TVA 50-259 DPR-33 50-260 DPR-52 50-296 DPR-68	205/729-6196 205/729-6197 FAX/729-6137	L. Wert, SRI - 06/12/94 J. Starefos, RI - 08/01/96 M. Morgan, RI - 04/30/95 *VACANT, Secretary	S. Sparks Ext. 15619	M. Lesser Ext. 10342	J. Williams 415-1470 PD II-3 F. Hebdon
BRUNSWICK 8470 RIVER ROAD SE SOUTHPORT NC 28461	CP&L 50-325 DPR-71 50-324 DPR-62	910/457-9531 910/457-9532 FAX/457-9154	C. Patterson, SRI - 07/24/94 M. Janus, RI - 07/12/93 P. Byron, RI - 10/23/91 *Joan Pessna, Secretary E. Brown, Intern	G.Wiseman Ext. 15533	M. Shymlock Ext. 15535'	D. Trimble 415-2019 PD II-1 E. Imbro
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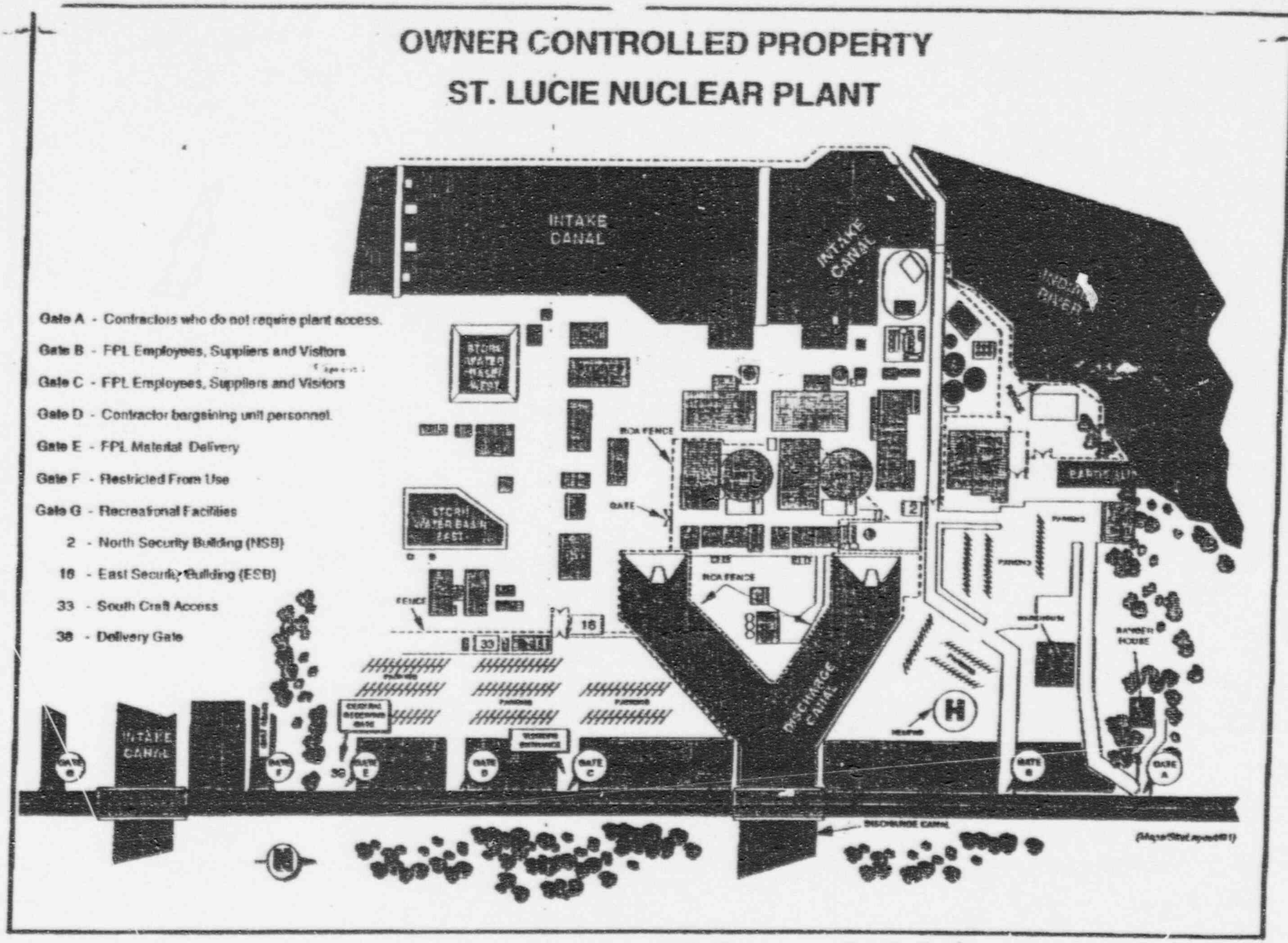
CRYSTAL RIVER 6745 N TALLAHASSEE RD CRYSTAL RIVER FL 34428	FPC 50-302 DPR-72	352/795-7677 352/795-7678 FAX/795-7564	R. Butcher, SRI - 08/10/93 T. Cooper, RI - 10/18/93 *Holly Fulton, Secretary	L. Mellen Ext. 15561	K. Landis Ext. 15509	L. Raghavan 415-1471 PD II-3 F. Hebdon
FARLEY 7388 N STATE HWY 95 COLUMBIA AL 36319	SNC, Inc. 50-348 NPF-2 50-364 NPF-8	334/899-3386 334/899-3387 FAX/899-3380	T. Ross, SRI - 10/19/93 R. Caldwell, RI - 08/30/96 J. Bartley, RI - 03/03/96 *Shirley Paul, Secretary	B. Wright Ext. 10345	P. Skinner Ext. 16299	J. Zimmerman 415-2426 PD II-2 H. Berkow
HARRIS 5421 SHEARON HARRIS RD NEW HILL NC 27562-9998	CP&L 50-400 NPF-63	919/362-0601 919/362-0602 FAX/362-0640	J. Brady, SRI - 03/15/96 D. Roberts, RI - 02/08/93 *Lucille Vuncannon, Secretary	G. Wiseman Ext. 15533	M. Shymlock Ext. 15535	N. Le 415-1458 PD II-1 E. Imbro
HATCH 11030 HATCH PKWY N BAXLEY GA 31513	GPC 50-321 DPR-57 50-366 NPF-7	912/367-9881 912/367-9882 FAX/367-6297	B. Holbrook, SRI - 06/12/94 E. Christnot, RI - 10/05/92 J. Canady, RI - 09/18/94 *Edna Dyal, Secretary	B. Wright Ext. 10345	P. Skinner Ext. 16299	K. Jabbour 415-1496 PD II-2 H. Berkow
MCGUIRE 12700 HAGERS FERRY RD HUNTERSVILLE NC 28078	DPC 50-369 NPF-9 50-370 NPF-17	704/875-1681 704/875-1682 FAX/875-9371	S. Shaeffer, SRI - 06/09/96 G. Harris, RI - 01/09/94 M. Sykes, RI - 05/15/94 *Sandy Poole, Secretary	S. Rudisail Ext. 15563	R. Crlenjak Ext. 15506	V. Nerses 415-1484 PD II-2 H. Berkow
'TH ANNA 4 HALEY DR .NERAL VA 23117	VEPCO 50-338 NPF-4 50-339 NPF-7	540/894-5421 540/894-5422 FAX/894-5650	R. McWhorter, SRI- 10/1/93 D.Taylor,RI leaves 10/13/96 *Esther Shears, Secretary	L. Garner Ext. 14663	A. Belisle Ext. 14196	B. Buckley 415-1452 PD II-1 E. Imbro
OCONEE 7812B ROCHESTER HWY SENECA SC 29672	DPC 50-269 DPR-38 50-270 DPR-47 50-287 DPR-55	864/882-6927 864/882-6928 FAX/882-0189	M. Scott, SRI - 07/19/96 G. Humphrey, RI - 11/28/93 N. Salgado, RI - 10/01/95 *Mary Jordan, Secretary	R. Carroll Ext. 15543	R. Crlenjak Ext. 15506	D. LaBarge 415-1495 PD II-2 H. Berkow
ROBINSON 2112 OLD CAMDEN RD HARTSVILLE SC 29550	CP&L 50-261 DPR-23	803/383-4571 803/383-4572 FAX/383-6441	SRI, VACANT J. Zeiler, Acting SRI - 09/03/95 *VACANT, Secretary	G. Wiseman Ext. 15533 J. Starefos 15583	M. Shymlock Ext. 15535	B. Mozafari 415-2020 PD II-1 E. Imbro
ST. LUCIE 7585 S HIGHWAY A1A JENSEN BEACH FL 34957-2010	FP&L 50-335 DPR-67 50-389 NPF-16	407/464-7822 407/464-7823 FAX/461-4622	M. Miller, SRI - 09/26/93 J. Munday, RI - 06/30/96 D. Lanyi, RI - 09/20/96 *Gail Anderson, Secretary	E. Lea Ext. 17096	K. Landis Ext. 15509	L. Wiens 415-1495 PD II-3 F. Hebdon
SEQUOYAH 2600 IGOU FERRY SODDY-DAISY TN 37379	TVA 50-327 DPR-77 50-328 DPR-79	423/842-8001 423/842-8002 FAX/842-8021	M. Shannon, SRI - 07/06/96 D. Starkey, RI - 06/12/94 D. Seymour, RI - 10/01/95 *Linda Wilson, Secretary	S. Sparks Ext. 15619	M. Lesser Ext. 10342	R. Hernan 415-2010 PD II-3 F. Hebdon
SUMMER RR 1 BOX 64 JENKINSVILLE SC 29065	SCE&G 50-395 NPF-12	803/345-5683 803/345-5684 FAX/345-5837	B. Bonser, SRI - 08/20/95 T. Farnholtz, RI - 09/05/93 *Pamela Bush, Secretary	L. Garner Ext. 15536	A. Belisle Ext. 14196	A. Johnson 415-1497 PD II-1 E. Imbro
SURRY 5850 HOG ISLAND RD SURRY VA 23883	VEPCO 50-280 DPR-32 50-281 DPR-37	757/357-2101 757/357-2102 FAX/357-7611	R. Musser, SRI - 08/03/96 K. Poertner, RI - 07/23/95 D. Kern, RI leaves 8/15/96 P. Byron, RI - 09/29/96 *Kathy Lippard, Secretary M. Branch leaves 8/1	L. Garner Ext. 15536	A. Belisle Ext. 14196	G. Edison 415-1448 PD II-1 E. Imbro
TURKEY POINT PO BOX 1448 HOMESTEAD FL 33090	FP&L 50-250 DPR-31 50-251 DPR-41	305/245-7669 305/245-7670 FAX/248-7254	T. Johnson, SRI - 09/04/93 B. Desai, RI - 07/25/93 *Hellen Maress, Secretary	E. Lea Ext. 13641	K. Landis Ext. 15509	R. Croteau 415-1475 PD II-3 F. Hebdon
'RTLE RIVER RD /NESBORO GA 30830	GPC 50-424 NPF-68 50-425 NPF-81	706/554-9901 706/554-9902 FAX/554-9548	C. Ogle, SRI - 08/20/95 M. Widmann, RI - 06/12/94 K. O'Donohue, RI 08/05/96 *Marilyn Evans, Secretary	R. Wright Ext. 10345	P. Skinner Ext. 16299	L. Wheeler 415-1444 PD II-2 H. Berkow
WATTS BAR 1260 NUCLEAR PLANT RD SPRING CITY TN 37381	TVA 50-390 NPF-90 50-391 CPPR-92	423/365-5487 423/365-5488 FAX/365-5496	K. VanDoorn, SRI-08/02/93 S. Cahill, RI- 03/14/95 *Linda Chattin, Secretary	P. Taylor Ext. 14199	M. Lesser Ext. 10342	B. Martin 415-1493 PD II-3 F. Hebdon



☐ PARK AT GATE C (NO ASSIGNED PARKING)

☐ BADGE IN AT BLDG 16

PLANT: **ST. LUCIE** LOCATION: **Ft. Pierce, FL**

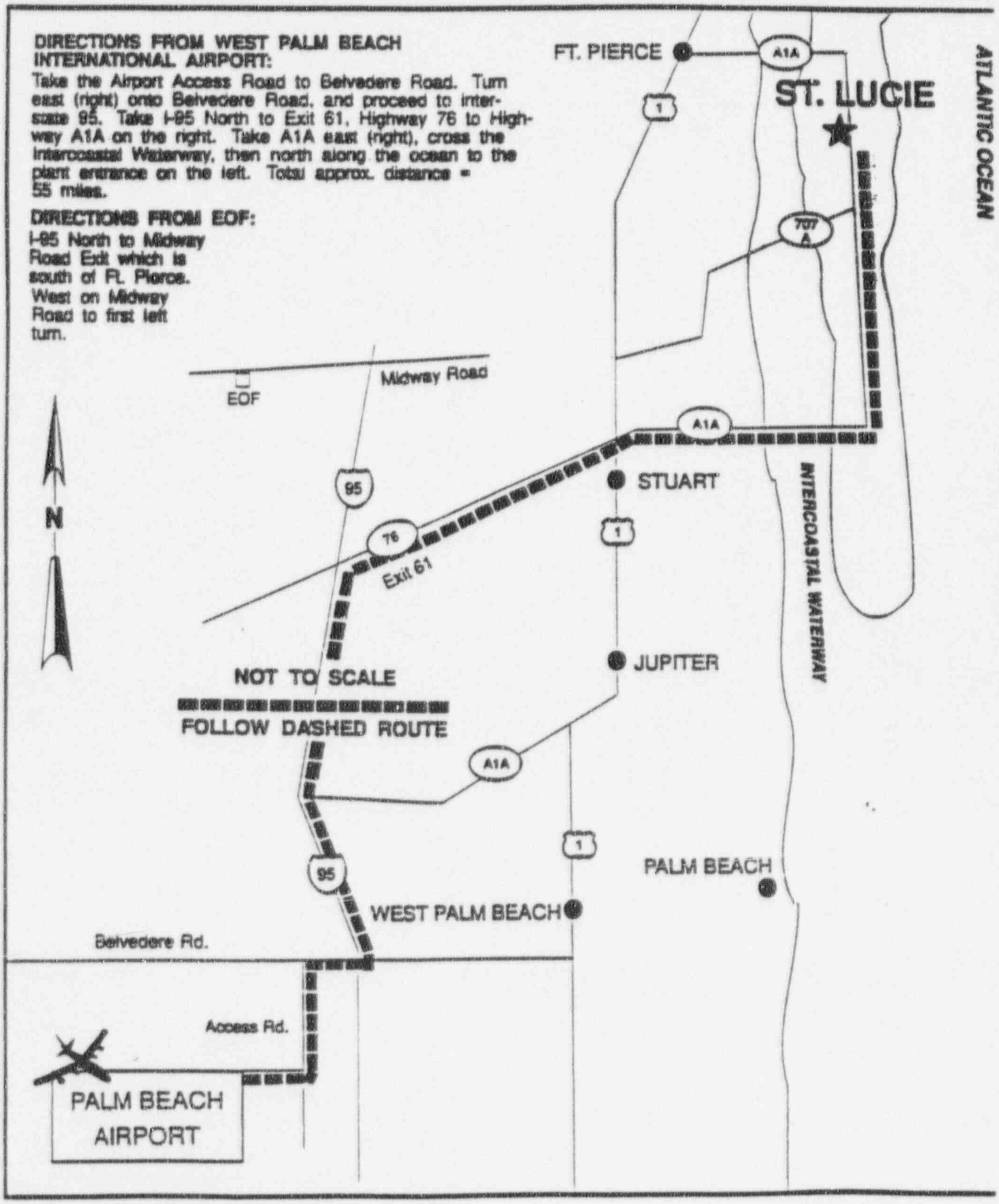
MEMBER UTILITY: **Florida Power & Light Company**

DIRECTIONS FROM WEST PALM BEACH INTERNATIONAL AIRPORT:

Take the Airport Access Road to Belvedere Road. Turn east (right) onto Belvedere Road, and proceed to interstate 95. Take I-95 North to Exit 61, Highway 76 to Highway A1A on the right. Take A1A east (right), cross the Intercoastal Waterway, then north along the ocean to the plant entrance on the left. Total approx. distance = 55 miles.

DIRECTIONS FROM EOF:

I-95 North to Midway Road Exit which is south of Ft. Pierce. West on Midway Road to first left turn.



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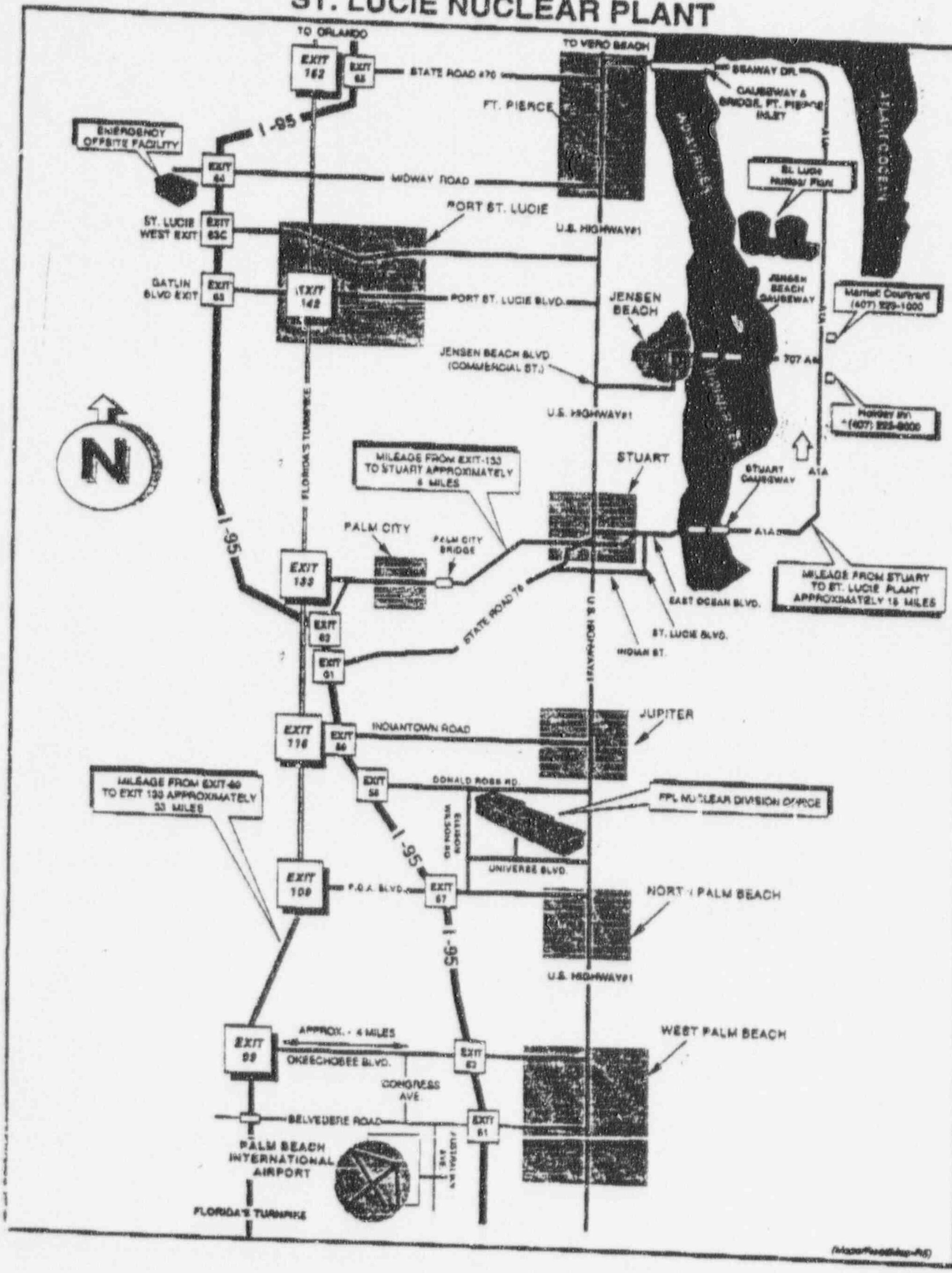
LOCATION MAP
ST. LUCIE NUCLEAR PLANT



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01/18/94

07-30-1996 10:34AM St Lucie Resident Office 1 407 461 4622 P.01

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

February 8, 1996

Florida Power and Light Company
ATTN: Mr. J. H. Goldberg
President - Nuclear Division
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE (SALP)
(NRC INSPECTION REPORT NO. 50-335/95-99; 50-389/95-99)

Dear Mr. Goldberg:

The Systematic Assessment of Licensee Performance (SALP) for the period January 2, 1994 through January 6, 1996, has been completed for St. Lucie. The results of the assessment are documented in the enclosed SALP report which will be discussed with you at a public meeting at the St. Lucie Site on February 22, 1996, at 1:00 pm. At the meeting, you should be prepared to discuss our assessment and any initiatives that address our concerns and challenges identified in the SALP report.

Overall the performance of the St. Lucie Plant was assessed as good over the performance period. The overall performance was mixed with the response to transient events being very good but routine activities performed at a somewhat lower level of performance. The engineering and plant support functional areas sustained the previously assessed ratings of superior performance, but there is a disturbing performance trend in the functional areas of operations and maintenance. Performance declined significantly in these areas from superior ratings that had been sustained over several past performance periods to a level of good performance. There is a concern that the long period of superior performance may have led to a pervasive complacent environment that is tolerant of equipment issues and a lack of discipline in adhering to procedures. There is evidence that the decline in human performance may be aggravated by inadequacies in the quality of the procedures themselves. Another contributor appears to be acceptance of a lower standard of performance by a significant part of the organization.

A further concern is the degree to which the performance declined before it was detected by the organization's self-assessment programs. There is a clear indication that these programs were not effective in identifying the trends early. It is too early to evaluate the effectiveness of the extensive corrective actions that were instituted in the very late part of the assessment period, but it is clear they must be aggressively pursued to terminate the negative trend in performance.

9602210074 -PP

In accordance with Section 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Should you have any questions or comments, I would be pleased to discuss them with you.

Sincerely,

Stewart D. Ebneter

Stewart D. Ebneter
Regional Administrator

Enclosure: As stated

cc w/encl:
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cc w/encl: Continued see page 3

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SALP REPORT - ST. LUCIE
50-335; 50-389
JANUARY 2, 1994 - JANUARY 6, 1996

I. BACKGROUND

The SALP Board convened on January 18, 1996, to assess the nuclear safety performance of St. Lucie Units 1 and 2 for the period of January 2, 1994, through January 6, 1996. The Board Meeting was conducted pursuant to NRC Management Directive 8.6, "Systematic Assessment of Licensee Performance." Board members were Ellis W. Merschoff (Chairperson), Director, Division of Reactor Projects, Region II (RII); Johns P. Jaudon, Deputy Director, Division of Reactor Safety, RII; and David B. Matthews, Director, Project Directorate II-1, Office of Nuclear Reactor Regulation.

The performance category ratings and the assessment functional areas used below are defined and described in NRC Management Directive 8.6, "Systematic Assessment of Licensee Performance (SALP)."

II. PERFORMANCE ANALYSIS - PLANT OPERATIONS

This functional area assesses the control and execution of activities directly related to operating the plant. It includes activities such as plant startup, power operation, plant shutdown, and response to transients.

Overall performance in the operations area has declined from its previous superior level to an overall rating of good. The plant has been operated safely, although there has been an increase in the number of operational events. This increase is attributable to the following: weaknesses in operator performance, the acceptance of long standing deficiencies in plant equipment, management expectations not effectively communicated to personnel and enforced, weaknesses in procedural adequacy and adherence, and the implementation and adequacy of corrective actions. Quality Assurance activities associated with Operations remained strong and effective in identifying areas for improvement.

Operator performance during the period has, overall, been good, and continued to be strong during unusual plant events or evolutions. Operators showed alert and proper response to ten reactor trips, reflecting well upon the licensee's training program and individual capabilities. Similarly, operator performance during twelve observed startups and seven monitored entries into reduced inventory conditions were typified by excellent command and control and thorough operator knowledge. However, operator performance during less demanding or less focused evolutions showed weaknesses in procedural adherence, the identification and correction of deficiencies, and attention to detail.

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Of particular concern, procedural adherence and adequacy issues resulted in, or contributed to, an increase in the number and severity of operational events. The lack of overall quality in plant procedures was underscored by the shear volume of procedural changes required when a policy of verbatim compliance was adopted.

The ability of Operations to identify and correct problems in a manner sufficient to prevent recurrence was also of concern. This issue was compounded by identified weaknesses in communications across organizational interfaces, in that failures in informal communications were not compensated for by programmatic methods.

Finally, operator attention to detail has declined during this SALP period. Given that issues of procedural inadequacies existed, the importance of attention to detail by operators was amplified, in that it represents an important barrier to failures. The decline in attention to details was indicative of an onset of complacency through the SALP period, a trend which operations management failed to identify and remedy in a timely manner.

The Plant Operations area is rated Category 2.

III. PERFORMANCE ANALYSIS - MAINTENANCE

This functional area assesses licensee activities in the areas of testing and maintaining plant structures, systems, and components. Activities assessed include preventive, predictive, and corrective maintenance, as well as surveillance, post-modification, and post-maintenance testing.

Overall performance in the maintenance area declined from its previous superior level to an overall rating of good. Maintenance provided generally effective support for plant operations on a day-to-day basis. However, there were problems with equipment that adversely affected overall plant performance and provided unnecessary challenges to operations.

Significant problems related to maintenance were manifested by an operability issue with pressurizer power-operated relief valves, reactor coolant pumps seal failures, and inadequate post-maintenance test determinations. There were also procedural difficulties encountered, especially in surveillance and preventive maintenance procedures. These issues had been present but unrecognized previously, and the licensee's remedial actions included an attempt to utilize a "verbatim compliance" approach. However, the older procedures were not written to a level of detail that would support this methodology, and the plant rank and file were not well oriented in the concept of procedural adherence; therefore, the use of verbatim compliance did not resolve the problems emanating from weak procedures.

SALP REPORT - ST. LUCIE
50-335; 50-389
JANUARY 2, 1994 - JANUARY 6, 1996

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33pp

Of particular concern, procedural adherence and adequacy issues resulted in, or contributed to, an increase in the number and severity of operational events. The lack of overall quality in plant procedures was underscored by the shear volume of procedural changes required when a policy of verbatim compliance was adopted.

The ability of Operations to identify and correct problems in a manner sufficient to prevent recurrence was also of concern. This issue was compounded by identified weaknesses in communications across organizational interfaces, in that failures in informal communications were not compensated for by programmatic methods.

Finally, operator attention to detail has declined during this SALP period. Given that issues of procedural inadequacies existed, the importance of attention to detail by operators was amplified, in that it represents an important barrier to failures. The decline in attention to details was indicative of an onset of complacency through the SALP period, a trend which operations management failed to identify and remedy in a timely manner.

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Significant problems related to maintenance were manifested by an operability issue with pressurizer power-operated relief valves, reactor coolant pumps seal failures, and inadequate post-maintenance test determinations. There were also procedural difficulties encountered, especially in surveillance and preventive maintenance procedures. These issues had been present but unrecognized previously, and the licensee's remedial actions included an attempt to utilize a "verbatim compliance" approach. However, the older procedures were not written to a level of detail that would support this methodology, and the plant rank and file were not well oriented in the concept of procedural adherence; therefore, the use of verbatim compliance did not resolve the problems emanating from weak procedures.

Management of the maintenance area changed during this assessment period, and by the end of the assessment period, the new management appeared to be providing the leadership necessary to reverse the observed negative trends. In the area of procedures, the new management team instituted a dual approach of correcting the procedures and training the personnel to use them which has seen some preliminary successes.

The surveillance program was implemented satisfactorily, but the procedural problems discussed above kept it from rising to the superior level. Corrective maintenance was performed acceptably and generally had strong management involvement.

In addition to the apparent strength of the new management team, the predictive maintenance group was considered a strength. The group was adept at vibration analysis, thermography, and lubrication analysis. The predictive maintenance group had strong and positive interactions with the operations and maintenance programs and, furnishing early warning of incipient equipment failures, and long-term degradation of important components.

Licensee preparations to implement the new maintenance rule were successful in identifying equipment such as the radiation monitoring system and the emergency diesel generators which were not performing to the licensee's expectations.

The Maintenance area is rated **Category 2.**

IV. PERFORMANCE ANALYSIS - ENGINEERING

This functional area assesses activities associated with the design of plant modifications and engineering support for operations, maintenance, surveillance, and licensing activities.

The overall performance in the Engineering area remained superior.

The strength of the engineering group was shown in the area of design and installation support. This was manifested by a number of well engineered and implemented plant modifications. In the area of design control and maintenance of the current licensing basis, the engineering organization typically performed well with occasional weaknesses.

The plant's operations were supported successfully throughout the assessment period. Of particular note was the design and installation on Unit 2 of the condenser tube cleaning system. In addition, the licensee has undertaken several initiatives to reduce the number of jumper/lifted leads, eliminate operator work-arounds, reduce the number of old work orders, and to improve the performance of contractors. The fuel vendor independence program will result in better control of core design, improved support for the plant and enhanced fuel utilization. The support of maintenance activities remained strong. The 45th Street Laboratory provided good support with component specialists along with effective nondestructive examination services. A comprehensive program of monitoring Alloy 600/690 applications focused on the pressurizer, reactor vessel and loop piping penetrations. The recently implemented maintenance specification program should result in effective maintenance support, efficient engineering, and enhanced plant safety. In light of the weaknesses discussed in the Maintenance section, the support of maintenance activities by engineering is an area where improvements could be achieved.

Throughout the assessment period, licensing submittals have been consistently of high quality, reflecting sound engineering judgment and appropriate attention to detail. Safety evaluations demonstrated the licensee's commitment to safety and compliance with regulations.

The Engineering area is rated **Category 1**.

V. PERFORMANCE ANALYSIS - PLANT SUPPORT

This functional area addresses radiological controls, radioactive effluents, chemistry, emergency preparedness, security, fire protection, and housekeeping controls.

The overall performance in the Plant Support area has remained superior.

The radiation protection program received strong management support. The accumulated dose goal was met for the first year of the assessment period but not for the second year. This was the result of the maintenance problems and the resulting increased outage time. The radiation protection organization continued to implement strong initiatives in the "as low as reasonably achievable" (ALARA) program through the use of remote monitoring of potentially high radiological dose work and the introduction of electronic dosimetry. Management involvement and support was evidenced by the small amount of surface area contamination, a significant reduction in the volume of solid waste, and the readiness of the post accident sampling system. Training and self-assessments were found to be effective. Thus, the combination of management support and an innovative health physics organization resulted in superior performance.

Security maintained an excellent level of performance during a staff reduction of the guard force and the introduction of biometrics. Measures used included effective training, which included the use of a combat firing range and good self-assessments. Changes to the security plan were both appropriate and made in a timely manner. However, there were some performance problems such as a repeat instance of failure to compensate in a timely manner for a computer failure; this suggested a problem with the effectiveness of corrective action from a previous event.

In the fire protection area, combustible control was effective and the fire brigade performed well during drills and during an actual event. However, observation of surveillance testing of the fire protection systems revealed weak procedures, poor attention to detail, as well as minor past errors that had gone uncorrected. On balance, procedural and surveillance problems detracted from the otherwise excellent level of performance in the fire protection area.

In the emergency preparedness area, the full participation exercise conducted in 1994 was successful, and appropriate emergency classifications were made. Overall exercise performance was rated as good. The status of equipment and supplies needed to support emergency preparedness was found to be adequate. The emergency preparedness program maintained a good state of readiness for event response.

The Plant Support area is rated **Category 1**.

SITE INTEGRATION MATRIX BY DATE

St. Lucie

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
8/9/96	EMERG	IR 96-14 (pending)	L	O	M	NOUE declared due to RCS leakage in excess of 1 gpm unidentified.	Charging pump packing leakage identified as source of leak.
8/3/96	VIO	IR 96-11 (pending)	N	E	M	Prelubrication of valves prior to surveillance testing in 1995 resolved as being a violation of 10CFR50 Appendix B criterion XI.	Procedure which required prelube had not been considered for potential effects on stroke time.
8/3/96	NCV	IR 96-11 (pending)	N	M		Review of outage freeze seals indicated that one freeze seal had been left unattended for approximately one hour.	Stop work order by management for cleanup of the Unit 1 pipe tunnel resulted in directing freeze seal watch to another area to make room for trash being hauled out of
8/3/96	OTHER	IR 96-11 (pending)	N	M	E	Licensee's activities regarding maintenance of rod control system were adequate.	
8/3/96	NCV	IR 96-11 (pending)	L	O		QA audit discovered that corrective action documents had been closed without being forwarded to originator for approval (as required by procedure). NRC identified that personnel without signature authority were closing documents.	Rush to close out STARs (old corrective action document) when CRs (new corrective action document) were instituted.
7/30/96	OTHER	IR 96-11 (pending)	L	O	M	3 of 4 Unit 1 linear NI channels found miswired, with the detectors' upper chambers feeding the lower NI drawer inputs and vice-versa. Result was 3 channels for which axial shape index was in error.	Drawing errors - discrepancy between vendor technical manuals and control wiring diagrams generated for the installation of the new Unit 1 NI drawers.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
7/20/96	NEG	IR 96-11 (pending)	L	O	M	2 opearting charging pumps tripped when maintenance induced an erroneous level signal into reactor regulating system. Letdown isolated by operators. Upon reinitiating letdown, minor waterhammer event occurred.	I&C failed to recognize that reactor regulating system would be affected by their activities.
7/20/96	POS	IR 96-11 (pending)	N	M	O	Post-outage walkdown of Unit 1 containment indicated excellent cleanliness.	
7/18/96	OTHER	IR 96-11	L	E	M	Unit 1 AFAS setpoints found nonconservative during review of recalibration activities.	Failure to employ as-built elevations of condensate pots in the development of calibration criteria.
7/16/96	NEG	IR 96-11 (pending)	L	O		2C auxilliary feedwater pump tripped on overspeed during post-maintenance testing.	Operator error in not properly implementing cautions in a procedure.
7/13/96	EMERG	IR 96-11 (pending)	L	O	M	NOUE declared when 2C charging pump check valve stuck open, creating bypass flowpath from charging pumps to VCT. Operators timely in declaring event.	Check valve stuck open due to possibly generic effects of pulsating low flow in a continuous service valve.
7/12/96	VIO	IR 96-12, EA 96-236	N	E		Five examples of a possible breakdown in configuration management control identified, involving inaccuracies in procedures and drawings due to design changes.	Lack of appropriate pre and post-installation review.
7/12/96	WEAK	IR 96-12	L	E		Licensee veritcal slice inspection of EDG, HPSI, and CCW systems revealed numerous deficiencies in procedure, design document and FSAR accuracy.	Lack of proper configuration control over time.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
7/9/96	STREN	IR 96-11 (pending)	N	O		Two entries into reduced inventory made during inspection period. Strong management involvement in scheduling around Hurricane Bertha. Reduced inventory operations continues to be a strength.	
7/8/96	POS	IR 96-11 (pending)	N	O	M	Licensee preparations for Hurricane Bertha proactive and responsible	Hurricane forcasts showed storm missing area, but licensee prepared as though it would change course.
7/6/96	VIO	IR 96-09	N	M	E	Review of testing activities for continment blast dampers indicated that violations of 10 CFR 50 App. B and site procedures existed. Two violations cited	Failure to properly implement App. B and QA plan as they related to documenting as-found and as-left data. Additionally, multiple examples of failures to properly
7/6/96	POS	IR 96-09	N	PS		Review of RCP oil collection system.	System met description in FSAR and was in accordance with App R, except as allowed by approved exemption.
7/5/96	POS	IR 96-09	N	O		Unit 1 reduced inventory preparations and execution.	Mid-Loop controls effective. Licensee attention and management oversight excellent.
6/27/96	OTHER	IR 96-09	L	O	E	Site reorganization announced which would place almost all engineering functions (system engineering, STAs, test engineers) under Engineering. Also, Outage Management folded into a global work planning group under the Plant General Manager.	
6/20/96	POS	IR 96-09	L	M	O	Loss of 3 Wide Range Nuclear Instrument Channels on Unit 1 resulted in entering TS AS for NIs.	Operators prompt and accurate in verifying shutdown margin requirements.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
6/19/96	POS	IR 96-09	N	O		Unit 1 reduced inventory preparations and execution.	Controls were appropriate.
6/13/96	POS	IR 96-09	N	M		Maintenance activities associated with Unit 1 reactor head lift and Unit 2 feed reg valve work.	Work conducted satisfactorily.
6/13/96	VIO	IR 96-09	N	M		A review of overtime for a one month period indicated that overtime guidelines were routinely exceeded without prior (or subsequent) approval. 56 examples cited for 5 individuals.	Failure of management to track the use of overtime as specified in site procedure. Procedure poorly defined requirements. Personnel had varying understandings of
6/8/96	POS	IR 96-08	N	O		3 QA audits reviewed	Broad in scope, appropriately focused, indicated an aggressive application of quality standards.
6/8/96	NEG	IR 96-08	N	M		Application of ladder and scaffolding programs appears to be minimally compliant with licensee's self-imposed requirements. Many scaffolds and ladders required caution tags or had not been removed promptly after use.	
6/8/96	OTHER	IR 96-08	N	M		Review of maintenance backlog indicated that licensee had a plan for backlog reduction in place but has yet to meet goals.	
6/8/96	VIO	IR 96-08	N	O	M	Testing of 1A and 1B EDGs following radiator replacement in each case included observations of inoperable temperature indicators and a lack of cognizance of the conditions by test personnel. Violation cited for failing to comply with procedure.	Lack of attention to detail by test personnel.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
6/8/96	POS	IR 96-08	N	M		Repair work for Unit 1 fuel transfer tube isolation valve.	Conducted satisfactorily
6/8/96	POS	IR 96-08	N	E	M	Unit 1 RWT liner inspection.	Licensee satisfied committments to inspect fiberglass liner in RWT. Results sat
6/8/96	OTHER	IR 96-08	L	E		Ongoing review by licensee of UFSAR accuracy identified approximately 150 items, ranging from typographical errors to more substantive issues.	Failure to update FSAR over time and failure to review FSAR properly when preparing procedures.
6/8/96	STREN	IR 96-08	N	E	M	ISI activities for SG and reactor vessel eddy current examinations reviewed.	Examinations well-planned, performed and managed by very talented and knowledgable personnel.
6/8/96	POS	IR 96-08	N	O		3 QA Audits reviewed	Broad in scope, focused on weak areas. Agressive application of standards evident in the number of findings cited.
6/8/96	POS	IR 96-08	N	PS		Fire barrier inspections performed by the licensee were found to employ conservative criteria nad be detailed.	
6/6/96	VIO	IR 96-12 , EA-96-249	N	E		Four 10 CFR 50.59 issues identified. One USQ, two failures to perform safety evals due to failure to screen issues, and one licensee-identified failure in the screening process that was later caught in FRG review.	One case of interpretation error, two of failing to employ system, one personnel error while performing screening.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
6/6/96	POS	IR 96-08	S	O		Unit 2 manually tripped due to high main generator gas temperature due to failed temperature control valve	Operators acted promptly and correctly in tripping the unit. Post trip response of both plant and operators was good.
6/3/96	NEG	IR 96-08	N	O		Poor practice observed in spent fuel pool operations. Fuel assemblies were left hanging in an "on deck" status while awaiting upender availability. Also, operator left machine unattended with fuel hanging at least once per movement.	"On deck" status was an effort to expedite reload. Operator leaving machine was due to inadequate manpower - operator had to operate upender controls, which were mounted on wall.
6/3/96	VIO	IR 96-12 , EA 96-236	S	M	E	High temperature condition in Unit 2 rod control cabinet room due to failure of an air conditioner led to indications of rod control problems. Indications later shown to be false. Also, high temp condition led to failure of a diverse turbine trip relay.	Failure of an air conditioner. Further review by licensee/NRC showed air conditioner was temporary equipment installed without design controls and room itself may have been constructed without seismic or appendix R reviews.
6/3/96	OTHER	IR 96-08	N	M		EDG reliability calculations indicate that EDG reliability is in keeping with SBO assumptions	
6/3/96	OTHER	IR 96-08	L	O	E	Unit 1 outage extended to July 19 due to expansion of SG MRPC tube inspections. 10 free-span indications identified to date. Projected tube plugging will exceed 25% limit. PLAs submitted to NRR to allow plugging up to 30%	New plugging criteria resulting from discussions with NRR on defect characterization methodologies.
6/2/96	LER		L	O	M	Non-safety related breaker alignments to support Unit 1 outage resulted in loss of audible count rate amplifier for containment. Audible counts lost in containment for approximately 5 minutes during fuel movements.	Operators not aware that containment amplifier was going to be affected by lineup. Control room amplifier not affected.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
6/1/96	POS	IR 96-08	N	E		CNRB activities surrounding PLA reviews in support of SG tube plugging issues were probing and competent.	
5/31/96	OTHER	IR 96-08	S	O	M	Blown fuse resulted in closure of all Unit 2 MSR temperature control valves, resulting in a 5% load rejection.	Moisture found in a junction box following heavy rain.
5/29/96	LER		L	O	M	Suspected loss of approximately 1200 condenser tube cleaning balls reported to state/NRC. Balls were found unaccounted for during an inventory balance. Suspected that balls were released to Atlantic Ocean.	
5/24/96	POS	IR 96-08	S	O	M	Rod control system failure resulted in inability to move (electrically) 4 CEAs. Operators conservatively interpreted TS to require shutdown in this instance. Situation complicated by an out of service Startup Transformer.	Operators conservative in interpreting TS, plant organizations provided timely support with lists of equipment which would be inoperable when the main generator was tripped.
5/22/96	OTHER		L	M		V 2483 (SDC Suction Relief) setpoint found out-of-spec high, rendering valve incapable of performing its intended function.	Root cause is yet to be established.
5/17/96	NCV	IR 96-08	N	M		Failure to verify the currency of procedure in use at jobsite	Cognitive personnel error
5/17/96	NCV	IR 96-08	N	M		Failure to satisfy requirements for "independence" on the part of independent verifier.	Cognitive error.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
5/15/96	NEG	IR 96-08	N	PS		Observations of radiation worker practices revealed inconsistencies in the application of site practices (e.g. wearing of dosimetry, donning/doffing PCs)	
5/14/96	POS	IR 96-08	N	O		Fuel movements during Unit 1 core offload and reload performed well	
5/14/96	NCV	IR 96-08	L	O		Fuel movement begun with only one of two required wide range NI channels operable. Condition identified and fuel movement secured after approximately 1 ft of travel.	Poor communication between control room operators performing surveillance testing on the subject channel and the refueling center. Compounded by operators not
5/12/96	VIO	IR 96-12 , EA 96-236	L	O	E	Initial temperature (and other) conditions specified in Unit 1 spent fuel pool heat load calculation (to support total core offload) was not factored into procedures. Additional examples of design control failures cited	Programmatic weakness in Plant Change/Modification process.
5/11/96	POS	IR 96-06	N	M		Observations of Pressurizer Code Safety Valve testing and repair	No deficiencies noted
5/11/96	POS	IR 96-06	N	O		2 clearances audited, both correct	
5/11/96	POS	IR 96-06	N	M	E	Polar crane load rating calc and Unit 1 head lift.	No deficiencies identified.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
5/11/96	POS	IR 96-06	N	M		MSSV testing - Unit 1 Outage	Review of test data and methodology sat.
5/11/96	POS	IR 96-06	N	M		Observations of maintenance activities in containment (Unit 1 outage) involving valve packing replacement and modification.	No deficencies noted.
5/11/96	POS	IR 96-06	N	M		Preparations for Unit 1 reactor vessel ISI.	In accordance with requirements and showed good outage planning.
5/8/96	NCV	IR 96-06	N	M		Lack of verified (controlled) copy of procedure identified at CCW heat exchanger jobsite.	Failure of Maintenance workers to properly verify procedures prior to beginning work.
5/7/96	VIO	IR 96-06	N	PS		Programmatic weaknesses identified in Fire Protection Program for medical qualification of fire brigade members.	11/62 members had expired medicals. 9/65 with expired medicals worked 60 shifts in April. 2 Fire Team leaders not listed on roster worked 31 shifts in April. 1 Fire Team member with expired medical and not on roster worked 1 shift.
5/5/96	POS	IR 96-06	N	O		Reduced inventory operations conducted well by operators.	
5/3/96	WEAK	IR 96-05	N	PS		Response letters prepared by Speakout to concerned employees did not contain adequate feedback to concerned employees.	

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
5/3/96	WEAK	IR 96-05	N	PS		Investigative techniques of Speakout program have the potential to reveal, inadvertently, of concerned employees.	No requirement to develop plans to ensure identity is protected.
5/3/96	POS	IR 96-05	N	PS		Inspection of FPL Speakout program.	Program effective in handling and resolving employee safety concerns.
5/3/96	WEAK	IR 96-05	N	PS		Speakout program corrective actions were not tracked through implementation as required.	Lack of procedural specificity.
5/2/96	POS	IR 96-06	N	O		Good performance by operators and test personnel during integrated safeguards testing on Unit 1. 1B EDG output breaker failed to close during first test. Operators handled situation well.	
4/29/96	NCV	IR 96-06	N	E		Failure to promptly document a nonconformance.	Engineering failed to initiate CR upon discovery that approx. 35 S-R instruments on each unit might have been calibrated at temperatures lower than those assumed in setpoint calcs.
4/28/96	POS	IR 96-06	N	O		Operators performed well during Unit 1 RFO shutdown.	Communications formal, excellent use of annunciator response procedure. Performance of rod drop time testing a noteworthy initiative.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
4/22/96	NCV	IR 96-06	L	O	E	Unauthorized breech in RAB fire barrier during installation of CCW piping modification.	Operators showed good attention to detail in identifying two holes bored in wall. Engineering failed to account for the effects of modification installation in fire rated assembly, as required by procedure for engineering packages.
4/20/96	OTHER	IR 96-06	S	O		Unit 2 downpowered and taken off-line due to low pressure condition in auto-stop oil. Operators observed to control evolution well.	Blockage in auto-stop oil line orifice which prevented buildup of auto-stop oil pressure. Only negative aspect was crowding of control panels by control room SROs during portions of evolution.
4/18/96	NCV	IR 96-06	L	E	M	Missing orifice plate identified in Unit 1 ICW system during licensee field walkdowns.	Either failure to install orifice during plant modification, ar failure to reinstall orifice following maintenance.
4/14/96	WEAK	IR 96-06	N	O	E	ICW system walkdown	Results indicate weaknesses in procedure-to-procedure agreement, labeling, and surveillance requirements, in addition to configuration control issues disussed separately.
4/14/96	WEAK	IR 96-06	N	O	E	Configuration Control issues resulted from ESF system walkdowns	Walksdowns of both units' CS, ICW and IA systems indicate programmatic failures in incorporating design changes into drawings, the FSAR and operating procedures. Unresolved Item tracking expansion of inspection scope to include instrumentation setpoints.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
4/13/96	POS	IR 96-06	N	E		Engineering response to failure of HVS-4A motor considered good.	Procurement engineering effective in locating and dedicating replacement motor and in identifying and resolving incorrect bearing rating calc for new motor. Minor problem existed in that new starting current profile was not adequately treated.
4/10/96	OTHER	IR 96-300	N	O		4 of 4 SRO candidates passed SRO examination. In 3 of the cases, performance was marginally satisfactory. No generic candidate weaknesses identified.	
4/10/96	POS	IR 96-300	N	O		Simulator performed well throughout SRO qualification testing.	
4/9/96	NEG		S	E		CIRC water piping through-wall leaks observed in two water boxes' outlets.	Galvanic corrosion due to inadequate cathodic protection following installation of stainless steel Tapparogge components.
4/4/96	OTHER	IR 96-06	L	O		Interim Operations Manager (H. Johnson) named.	
3/31/96	EMERG	IR 96-06	N	O	PS	Operator response to RCS leakage through CVCS system.	Operators effective at identifying/isolating leak; however, Unusual Event call was non-conservative in that the call was delayed to allow a 1 hour RCS inventory balance to be calc'd when other information indicated that excessive leakage existed.

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
3/30/96	NEG	IR 96-04	N	M		Control of maintenance procedures was such that an outdated procedures could, programmatically, wind up in the field due to their inclusion in previously prepared packages. Licensee corrective action adequate.	Programmatic vunerability.
3/30/96	POS	IR 96-04	N	M		10 maintenance activities observed during inspection period. No significant deficiencies noted.	
3/30/96	OTHER	IR 96-04	S	M		Maintenance underwent major departmental reorganization. Selected supervisors' qualifications found satisfactory per TS requirements.	
3/30/96	POS	IR 96-04	N	O		Review of 5 clearances indicates better attention to detail than had been observed in past.	
3/29/96	POS	IR 96-04	N	O		Operator requalification program found to be supporting management expectations for operations and covering timely and important topics.	
3/27/96	VIO	IR 96-04	N	O		Operators failed to properly log boron dilution evolutions. Global log entry was made at the beginning of the shift stating dilutions would be made; however, procedure required each dilution to be logged.	Management direction to operators allowing global log entries for reactivity manipulations during transient conditions (e.g. uppower) which was not in accordance with Conduct of Operations procedure.
3/14/96	OTHER		L	PS		Management change. A. Desoiza (human resources manager) replaced by Lynn Morgan (from TP)	

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
3/12/96	POS	IR 96-04	S	O		Licensee disposition for deficiency noted in 1 boroflex panel (top 15" missing) found satisfactory. FRG treatment of issue found appropriate.	
3/10/96	OTHER	IR 96-04	L	O		Unit 1 downpowered to 97.5% due to hot leg stratification and flow swirl which resulted in higher than actual indicated reactor power.	Hot leg stratification.
3/7/96	NEG	IR 96-04	N	O		During MTC testing, inspector noted that boron concentration had been verified at 30 minute intervals, vice 15 minute intervals as called for in procedure.	Poor attention to detail.
3/7/96	NEG	IR 96-04	N	O		Licensee failed to place a CEA which had been declared administratively inoperable in the equipment out-of-service log. CEA was operable per TS.	Operator oversight.
3/1/96	OTHER	IR 96-04	N	PS		Licensee found to be utilizing ALARA techniques and making progress at reducing collective doses for staff.	
3/1/96	OTHER		L	O		Management Changes - T. Plunkett succeeds G. Goldberg, C. Wood replaces L. Rogers as manager of SCE, C. Marple replaces C. Wood as Ops Supervisor.	
3/1/96	OTHER	IR 96-04	N	PS		Licensee found to be implementing adequate RP controls and monitoring individual exposures per code requirements.	

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
3/1/96	OTHER	IR 96-04	N	PS		Housekeeping in RABs generally good; however, equipment storage areas found cluttered and untidy.	
3/1/96	POS	IR 96-04	N	PS		Ongoing HP efforts to obtain accreditation of FPL electronic dosimetry program identified as a good example of department's technical capabilities.	
3/1/96	NCV	IR 96-04	N	PS		Inspection of Hot Tool Room identified several tools which were either not painted purple (as required) or which slightly exceeded limits for contamination.	Attention to detail in tool storage and surveying.
2/24/96	WEAK	IR 96-04	S	O		Procedural weakness results in attempting to synchronize main generator with grid with generator disconnect links open.	Procedure review weakness - lack of verification that disconnect links were closed.
2/24/96	VIO	IR 96-04	N	M		Acceptance criteria specified for CEDM coil resistances in PC/M package found varied and unclear. Criteria were not properly applied and values outside of specifications were not documented and resolved.	Failure of I&C System Supervisor to adhere to test criteria compounded by failure of I&C management to identify obvious errors during post-work review.
2/24/96	VIO	IR 96-04	L	PS	O	Unit 1 containment radiation monitor found out-of-service due to isolation valve which was closed to support a grab sample prior to a containment entry and not returned to the open position. Condition existed for 2 days, unknown to licensee.	Failure to follow procedure on the part of HP personnel, compounded by failure to identify condition by operators during rounds.
2/24/96	WEAK	IR 96-04	N	M		Maintenance practices for Steam Bypass and Control System and Feedwater Regulating valves found weak in inspection following 2/22/96 Unit 1 trip.	Poor preventive maintenance on SCBC valve air lines and FRVs.

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2/22/96	EMERG	IR 96-04	S	O		Dropped CEA (due to SCR failure) leads to TS-required shutdown and declaration of NOUE. Failure of air supply to FRV leads to operators tripping reactor from 26%. Good operator performance throughout.	Equipment Failure
2/22/96	VIO	IR 96-04	N	O	O	Operators found adding boric acid to VCT without procedure in hand, as required by conduct of operations procedure. Additional example of EEA 96-040.	Procedures were put away to tidy up control room prior to NRC senior managers' tour prior to SALP meeting.
2/17/96	POS	IR 96-01	N	M		Noted improvements in housekeeping and material conditions.	
2/17/96	NEG	IR96-01	N	M		Freeze seal procedure lacked objective criteria defining when a freeze seal existed.	Procedural Weakness
2/17/96	NCV	IR 96-01, IR 96-04	N	M	PS	Work on 1A ECCS suction header through-wall leak revealed strong FME, but poor HP work practices observed regarding contamination control resulted in NCV.	Personnel work practices (workers ignored RWP requirements)
2/17/96	WEAK	IR 96-01	N	O	E	Numerous deficiencies identified in instrument air system walkdowns, including drawings accuracy, ONOP adequacy, and annunciator response procedure accuracy.	Procedural Inadequacy
2/17/96	NEG	IR 96-01	L	M		Weakness identified in I&C calibration procedure - lack of detail provided for safety related calibrations.	Procedural Inadequacy

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2/15/96	NEG	IR 96-01	N	O	M	Tours of ECCS rooms revealed several active leaks. Licensee could not explain how (if) FSAR assumptions on ECCS leakage were satisfied. Later review of FSAR indicated leakage within assumptions.	Material Condition
2/7/96	POS	IR 96-02	N	PS		Licensee made significant observation of E-Plan execution - 2 practice drills were required prior to graded exercise for management to be satisfied with performance. Management determined that more frequent drills were required to ensure readiness.	Licensee objectively questioning overall state of readiness.
2/7/96	NEG	IR 96-02	N	PS		Two areas for improvement identified in graded EP exercise - Need for management to become more involved in assuring correctness of info being provided in offsite notification forms and need to refine C&C for damage control teams.	Inconsistencies in the use of Florida Notification Message Form. Confusion existed between NLOs dispatched from OSC and Control room for similar repair missions.
2/7/96	POS	IR 96-02	N	PS		Licensee's onsite emergency organization was found to be well-defined and generally effective at dealing with simulated emergency during graded exercise.	
2/7/96	POS	IR 96-02	N	PS		Communication among the licensee's emergency response facilities and emergency organization and emergency response organization and offsite authorities were good during graded exercise.	
2/7/96	OTHER	IR 96-02	N	PS		EP exercise demonstrated that onsite emergency plans were adequate and that licensee was capable of implementing them.	

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
2/7/96	POS	IR 96-02	N	PS		Observations of licensee performance in CR, TSC, OSC, and EOF indicated good command and control, staff utilization and staff demeanor during graded exercise	
1/26/96	OTHER	IR 96-01	N	O		Inspection of corrective action program revealed timely action on the part of management, but weaknesses in plans for tracking progress on personnel performance and procedure quality improvement.	Corrective Actions
1/26/96	VIO	IR 96-01 - VIO 96-01-01	N	O		Violation identified regarding temporary changes to procedure which changed intent and which were approved for use without prior FRG review.	Procedure Control
1/22/96	VIO	IR 96-03 - EA 96-040	L	O	E	Boron dilution event due to operator leaving control panel while dilution was in progress. Weak command and control, procedural adherence, and short-term turnover. Additionally, OP for boration/dilution not consistent with FSAR and no 50.59 performed.	Operator error, poor short term turnover, poor command and control
1/7/96			N	O		SALP CYCLE 12 BEGINS	
1/5/96	NCV	IR 95-22 - NCV 95-22-01	N	O	PS	Several deficiencies in prodecure change process implementation identified. Expired or cancelled TCs found in control rooms and hot shutdown panel.	Failure to Properly Implement Procedures

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1/5/96	NEG	IR 95-22	N	O		Several procedural deficiencies and calculational errors identified in reload physics test procedure.	Inadequate Procedure Review and Execution
1/5/96	WEAK	IR 95-22	L	O	M	U2 manual RX trip on high generator H2 temp due to failure of temp control valve. Operator awareness of RPS status post-trip poor. Inspection of post-trip review(for current trip as well as past trips)indicated weaknesses in the rigor of post-trip reviews	Temp Control Valve Failure
1/5/96	VIO	IR 96-04	L	O		NLO failed to employ procedure when placing EDG fuel oil tank on recirculation for chemistry. As a result, he improperly performed the evolution by isolating the discharge of the EDGFO transfer pump, which resulted in an inoperable EDG.	Failure to use procedure, failure to notify control room of evolution.
12/27/95	NEG	IR 95-22	S	O	E	FRG meeting suffered/items deferred due to lack of OPS/Eng'g attendance at meeting. Major issues at meeting affected OPS/Eng'g.	Lack of Attendance at FRG
12/20/95	OTHER	IR 95-22	S	M		RX vessel flange inner O-ring groove pitting resulted in cooldown and head removal for repair.	Pitting - Localized Corrosion
12/9/95	OTHER	IR 95-22	L	M		2A2 RCP seal pkg lower seal destaged due to reverse pressure across seal.	Filling RCS Before Coupling RCP
12/5/95	WEAK	IR 95-22	N	O	M	ESFAS cabinet doors found unlocked following maintenance work - I&C error. Log entries associated with work were not complete.	Poor Logkeeping/Attn to Detail

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12/1/95	NEG	IR 95-21	N	PS		Rad survey results unavailable for B hot leg work. Surveys performed but not documented.	Failure to Document RAD Survey
12/1/95	NEG	IR 95-21	N	O		Operators unable to effectively obtain I&C setpoints from computer after hard copies were removed from control room	Inadequate Operator Training
12/1/95	NEG	IR 95-21	N	O		Unit 2 procedures and valve deviation log used to cycle Unit 1 cross connect valves.	Valve Position Administrative Controls
12/1/95	WEAK	IR 95-21	N	O		SDC procedure contained conflicting values for RX cavity level requirements. Procedure had been approved since emphasis on accuracy stressed.	Procedural Weakness/Inadequate Review
12/1/95	WEAK	IR 95-21	N	O		CCW sample valve showed dual indication without corrective action documentation initiated.	FTF Procedure
12/1/95	WEAK	IR 95-21	N	O		Clearance in place to isolate N2 from CST to facilitate pressure switch replacement for nine days without work order being written.	Poor Corrective Actions
12/1/95	NEG	IR 95-21	N	O		Recurrent non-valid alarms when starting fire pumps were not documented as operator workarounds. Voltage dips associated with such starts were contributors to a trip previously.	FTF Procedure

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12/1/95	WEAK	IR 95-21	N	O		Followup to previous inspection findings indicated a weakness in followthrough in addressing deficiencies.	Corrective Actions
12/1/95	NEG	IR 95-21	N	O		SDC Procedure required natural circ-related surveillance prior to establishing RCS pressure boundary. Natural circ not possible without pressurization.	Procedural Inadequacy
11/27/95	VIO	IR 95-21 - VIO 95-21-03	L	O		Missed RCS Boron sample surveillance - Repeat from IR 95-18.	Personnel Error
11/21/95	NCV	IR 95-21 - NCV 95-21-04	L	O		Failure to maintain Penetration Log.	FTF Procedure
11/21/95	OTHER	IR 95-21	S	O		Light socket failure during lamp replacement results in loss cooling to 1A Main Transformer. Unit downpower to ~60%.	Equipment Failure
11/20/95	VIO	IR 95-21 - VIO 95-21-01	N	O		Valve discovered Closed vice Locked Closed as specified on Equipment Clearance Order.	FTF Procedure
11/16/95	OTHER	IR 95-21	S	O	M	Unit 1 manually tripped when 1B MFRV locked in 50% position. Root cause - degraded power supply, compounded by voltage dip on starting both station fire pumps.	Long-Standing Equipment Problem

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11/11/95	VIO	IR 95-21 - VIO 95-21-02	N	O		Tech. Spec. equipment not specified for IV on Equipment Clearance Order.	FTF Procedure
11/6/95	OTHER	IR 95-21	S	M		Failure of EDG 2A relay sockets. Potential common mode failure.	Equipment Failure
? 11/1/95	NCV	IR 95-18 - NCV 95-18-05	S	M		ICI wiring error during RX head installation last RFO.	Personnel Error
10/19/95	NCV	IR 95-18 - NCV 95-18-06	S	O		Missed shift CEA position indication surveillance.	Personnel Error
10/18/95	NCV	IR 95-18 - NCV 95-18-07	L	O		Missed RCS Boron sample surveillance.	Personnel Error
10/17/95	WEAK	IR 95-18	S	O		Lack of attention to task resulted in overfilling RCB lower cavity during flood up.	Personnel Error
10/12/95	VIO	IR 95-18 - VIO 95-18-04	S	E		Inserting CIAS signal during safeguards test shifted EDG 2A to isochronous mode while EDG paralleled with offsite power.	Design Error

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10/9/95	LER	LER 95-S02	L	PS		Potential route for unauthorized access to protected area, CW water piping.	Personnel Error
10/7/95	VIO	IR 95-18 - VIO 95-18-01	N	O		Did not enter bypass key position in deviation log.	Failure to Follow Procedures
10/5/95	OTHER	IR 95-18	S	M		DG 1B developed FO leak at threaded connection during surveillance run.	Equipment Failure
9/30/95	VIO	IR 95-18 - VIO 95-18-02	N	O		Did not enter bypass key position in deviation log.	Failure to Follow Procedures
9/28/95	OTHER	IR 95-18	S	E		Leaking PZR SVs extended forced outage - problems with tailpipe alignment.	Equipment Failure
9/20/95	OTHER	IR 95-18	S	M		EDG 1A/1B governor control problems resulted in load oscillations.	Equipment Failure
9/15/95	VIO	IR 95-18 - VIO 95-18-03	S	O	M	Main/Ops did not provide clearance for work on condenser waterbox cover. When cover pulled closed, severed worker's finger.	Failure to Follow Procedures
9/14/95	WEAK	LER U1/U2 95-S01	L	PS		Security failed to take correct compensatory action on computer failure.	Failure to Follow Procedure

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
9/10/95	WEAK	IR 95-18	S	O		SG blowdown sent to incorrect system on RAB roof. Operator used wrong procedure. When identified did not back out of procedure correctly.	Failure to Use Correct Procednue
9/9/95	WEAK	IR 95-15	S	M		Leak on SV 1201 flange extended outage, identified one month earlier but not worked.	Weakness in Work Screening and Planning
9/7/95	WEAK	IR 95-15	L	O		Unit 2 Main Generator overpressurized while filling with H2. Inattention by operators.	Personnel Error/Inoperable Equipment/OWA
9/2/95	VIO	IR 95-15 - VIO 95-15-03	N	O		Weaknesses identified in logs relating to abnormal equipment conditions and out of service equipment not logged (mulitple examples).	Personnel Error
8/31/95	OTHER	IR 95-15	S	M		Damaged cylinder and head on 1B EDG due to loose lash adjustment.	Personnel Error
8/30/95	WEAK	IR 95-15	N	PS		Containment closure walkdowns by management were inadequate and depended heavily on QC involvement to identify deficiencies.	Management and QC Weaknesses
8/30/95	WEAK	IR 95-15	N	M		Maintenance personnel not using procedures for work in progress.	Supervisory Oversight and Worker Attitude

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
8/29/95	VIO	IR 95-15 - VIO 95-15-04	L	O		Started 1B LPSI pump with suction valve closed. (No damage to pump)	Personnel Error
8/29/95	VIO	IR 95-15 - VIO 95-15-06	N	M		Maintenance journeyman not signing off procedure steps as work completed (previously identified as a weakness in May 1995).	Procedure Use
? 8/23/95	WEAK	IR 95-15	S	M		2A HDP trip due to relay failure. Eight HDP trips in past year. Engineering solution available but not implemented.	Equipment Failure/Inadequate Corrective Action
8/22/95	VIO	IR 95-15	N	PS		QA failed to document a deficiency on containment spray valve surveillance identified in an audit.	Personnel Error
8/19/95	WEAK	IR 95-15	S	O		Overfill of PWT. Spilled approx. 10K gallons on ground inside RCA. Operator work around on level control system and inattention to filling process by operator caused error.	Operator Error/Operator Workaround
8/18/95	WEAK	IR 95-15	N	M		Procedural weakness involving supervisory oversight and journeyman qualification.	Procedural Weakness
8/17/95	VIO	LER U1 95-007 - VIO 95-15	S	O		Spraydown of Unit 1 containment. STAR process did not assign accountability for corrective action. Valve surveillance prelube not documented on STAR.	Procedural Inadequacy and Weakness/Operator-Work-Around

DATE	TYPE	SOURCE	ID	SFA PRIM	SFA SEC	ITEM	APPARENT CAUSE / COMMENTS
8/9/95	VIO	IR 95-16 - LER U1 95-005 - EA 95-180	L	M		Inoperable Unit 1 PORVs due to maintenance error/testing inadequacies. (Valves assembled incorrectly) (Used acoustic data only)	Maintenance/Testing Errors
8/6/95	VIO	LER U1 95-006 - VIO 95-20-01	S	E		Lifting of Unit 1 SDC thermal relief due to procedural revision from previous corrective action. Inoperable equipment not logged.	Corrective Action/Procedural Weakness
8/2/95	VIO	LER U1 95-004 - VIO 95-15-02	L	O		1A2 RCP seal failure due to "restaging" at high temperature.	Procedural Weakness/Failure to Follow Procedures
8/2/95	VIO	LER U1 95-04 - VIO 95-15-01	S	O		Operator failed to block MSIS actuation during cooldown.	Operator Error

SALP Functional Areas:

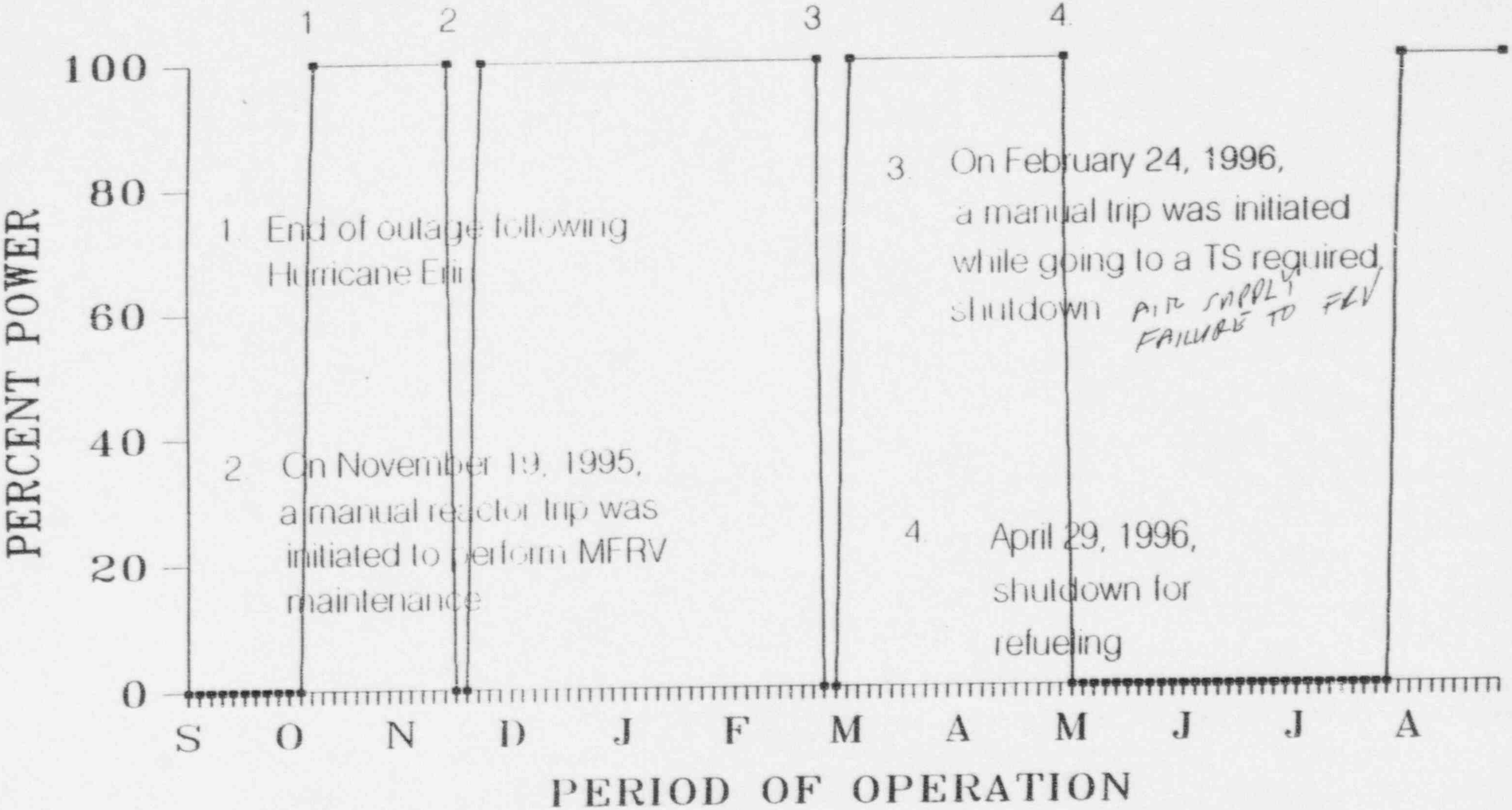
E	ENGINEERING
M	MAINTENANCE
O	OPERATIONS
PS	PLANT SUPPORT
SA	SAFETY ASSESSMENT & QV

ID Code:

L	LICENSEE
N	NRC
S	SELF-REVEALED

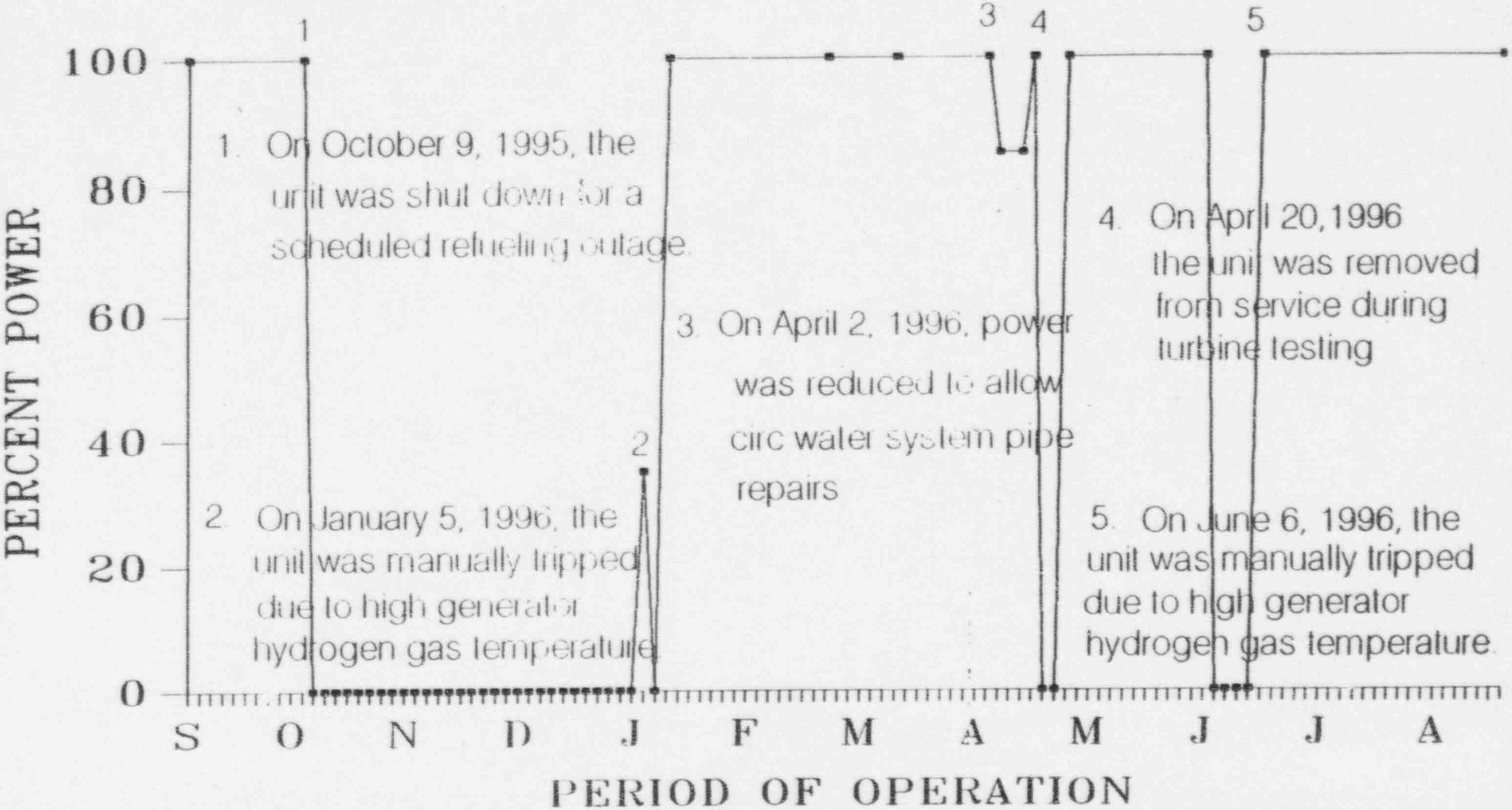
ST. LUC UNIT 1

Operational Period September 1995
through August 23, 1996



Graph does not include power reductions
for routine repairs, waterbox cleaning,
or required repairs.

ST. LUC UNIT 2
Operational Period September 1995 through August 23, 1996



Graph does not include power reductions for routine repairs, waterbox cleaning, or required repairs.

TAB E

MAINTENANCE RULE BASELINE INSPECTION REPORT OUTLINE

Cover Letter
Cover Page
Executive Summary

Report Details:

Summary of Plant Status

Introduction

I. OPERATIONS

O4 Operator Knowledge and Performance

O4.1 Operator Knowledge of Maintenance Rule (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Scope of Structures, Systems, & Components Included Within the Rule (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.2 Safety (or Risk) Determination (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.3 Periodic Evaluation (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.4 Balancing Reliability and Unavailability (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.5 Plant Safety Assessments Before Taking Equipment Out-of-Service (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.6 Goal Setting and Monitoring for (a)(1) SSCs (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M1.7 Preventative Maintenance and Trending for (a)(2) SSCs (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition Walkdowns (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

M7 Quality Assurance in Maintenance Activities

M7.1 Licensee Self Assessment (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

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/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. **???????????????? NEED TO MAKE SURE THIS IS DONE!!!!!!!!!!!!!**

E4 Engineering Staff Knowledge and Performance

E4.1 Engineer Knowledge of the Maintenance Rule (62706)

a. Inspection Scope

b. Observations and Findings

c. Conclusions

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

LICENSEE:

NRC:

LIST OF INSPECTION PROCEDURES USED

IP 62706 Maintenance Rule

LIST OF ITEMS OPENED, CLOSED, DISCUSSED

ATTACHMENT 2

LIST OF PROCEDURES REVIEWED

TAB G

INSPECTION FINDING FORM

TAB G
INSPECTION FINDING FORM

NUMBER:

REV:

DATE:

INSPECTION FINDING

INSPECTION AREA:

INSPECTOR:

EFFECTED ITEM OR EQUIPMENT:

REQUIREMENTS: (site full references)

DISCUSSION OF FINDING(S): (characterize as strength or weakness)

PROBABLE CAUSE OF FINDING:

LICENSEE RESPONSE TO FINDING:

CONCLUSION:

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 21, 1996

EGM 96-002

MEMORANDUM TO: Hubert J. Miller, Regional Administrator
Region I
Stewart D. Ebneter, Regional Administrator
Region II
A. Bill Beach, Regional Administrator
Region III
L. Joe Callan, Regional Administrator
Region IV
Roy Zimmerman, Associate Director for
Projects, NRR
Ashok C. Thadani, Associate Director for
Inspection and Technical Assessment, NRR
Elizabeth Q. Ten Eyck, Director, Division of
Fuel Cycle Safety and Safeguards, NMSS
Donald A. Cool, Director, Division of
Industrial and Medical Nuclear Safety, NMSS
John T. Greeves, Director, Division of Waste
Management, NMSS

FROM: Joseph R. Gray
Joseph R. Gray, Acting Director
Office of Enforcement

SUBJECT: ENFORCEMENT GUIDANCE MEMORANDUM INTERIM GUIDANCE FOR 10 CFR 50.65 - THE MAINTENANCE RULE

This Enforcement Guidance Memorandum (EGM) is being issued to provide interim enforcement guidance for evaluating issues that may be identified during maintenance rule inspections of licensee facilities. The enclosed guidelines have been developed in close coordination with the Division of Reactor Controls and Human Factors of NRR.

The guidelines in the attachment are intended to provide guidance to the NRC staff to facilitate consistent categorization of severity levels for failing to comply with the requirements of the maintenance rule. It is important to note that these guidelines are not currently contained in the Enforcement Policy and are, therefore, not controlling. They should be used to assist in applying the definition in Section IV of the Policy for: (1) instances of very significant regulatory concerns (for Severity Level II violations), (2) significant regulatory concerns (for Severity Level III violations), or (3) more than of minor concern (for Severity Level IV violations).

It is recognized that maintenance issues can overlap with other issues such as quality assurance and operability. For some enforcement considerations, other issues relative to the case may result in another enforcement approach being taken. In some cases, the issues can be categorized by either result or the root cause. For example, in some instances, the root cause may be more

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significant than the result, whereas in other circumstances, the opposite may hold true. In deciding whether to use the enclosed guidance or the existing Supplement I to the Policy, the selection should normally be whichever provides the higher severity level and the clearer message.

The form and philosophy of the rule encourages "maximum flexibility" for licensees in establishing their programs to meet the intent and requirements of the rule. Within these broad requirements, enforcement action would be appropriate for licensees who have inadequately implemented aspects of the rule or whose performance demonstrates a continuing ineffectiveness of maintenance activities.

Escalated enforcement would be appropriate where there was a failure to make reasonable efforts to implement the requirements of the rule or where significant degradation of SSCs could have been prevented through effective implementation of the maintenance rule. The following presents general guidance that is more fully expanded in the examples in the attachment:

- A single violation would be a Severity Level IV violation

NOTE: In considering whether to make a citation for a violation involving a relatively isolated, low safety significant SSC, consider the flexibility in the rule; the risk significance of the SSC; the reasonableness of the licensee's efforts to implement the rule, including consideration of its and industry's prior operating experience; and the licensee's corrective action. If the licensee has acted reasonably, a citation might not be warranted.

- A single violation involving a high safety significant SSC that causes a plant transient that would have been prevented by effective implementation of the maintenance rule would be a Severity Level III violation. Supplement I, Example C.9, provides that equipment failures caused by inadequate or improper maintenance that substantially complicates recovery from a plant transient is considered a Severity Level III violation or problem.

- Multiple examples of maintenance failures that demonstrate a "programmatic breakdown," would normally be considered a Severity Level III violation. This is consistent with Supplement I, Example C.7, which provides that a breakdown in the control of licensed activities involving a number of violations that are related that collectively represent a potential carelessness toward licensed responsibilities is considered a Severity Level III violation or problem.

- Multiple examples of maintenance failures of high safety significant SSCs that cause a plant transient or complicate the recovery from a plant transient, indicate a programmatic breakdown in implementation of the requirements of the rule and would be considered a very significant regulatory concern and should be considered for issuance as a Severity Level II violation or problem.

The maintenance rule does not supersede any existing requirements, such as those contained in 10 CFR Part 50 (including Appendix B and other sections) or a licensee's technical specifications. These requirements remain in effect for maintenance activities. When preparing notices of violation for maintenance activities, the maintenance rule should be used for citations whenever a licensee has violated a specific requirement of the maintenance rule. When a set of facts indicates that there are violations of both the maintenance rule and another NRC regulation, cite both requirements with only one "contrary to." However, where maintenance violations are caused by licensee activities not covered by the maintenance rule, cite against the requirements of Appendix B or the plant technical specifications. Also, please note that the failure to perform the safety assessment provided for in 10 CFR 50.65 (a)(3) requires special attention. This is addressed in Part A, Paragraph D in the attachment.

Because the maintenance rule takes a performance based approach to inspecting licensee maintenance operations (a relatively new technique with limited enforcement experience in these types of performance based inspection activities), it is anticipated that the guidance provided in the attachment will require modification as more inspections are completed and further experience is gained. It is estimated that a minimum of six months will be required until sufficient information can be collected. At that time, the Office of Enforcement expects to revise the Enforcement Policy by adding further guidance to the supplements, after consulting with the Commission.

Additional enforcement guidance has been provided in EGM 96-001, dated July 3, 1996, which established a Maintenance Rule Enforcement Review Panel that will meet periodically to review enforcement issues that are disclosed during the performance of maintenance rule and other routine NRC inspections. This should contribute to the consistency of enforcement actions in this area.

cc: J. Milhoan, DEDR
H. Thompson, DEDS
W. Russell, NRR
J. Goldberg, OGC
F. Gillespie, NRR

ATTACHMENT 1: MAINTENANCE RULE VIOLATIONS

I. Examples of Activities That Would Be Violations of the Maintenance Rule:

A. Failure to include safety related[1] or non-safety[2] related structures, systems, and components (SSCs) (as defined in 10 CFR 50.65 (b)(1) and (2)) within the scope of the program.

1. Severity Level III - violations involving, for example:

   a. Failure to include one or more SSCs, where they should clearly be included within the scope of the rule, that as a result of the failure to include the SSC: 1) complicates the recovery from a plant transient or 2) in the case of high safety significant SSCs, causes a plant transient (if this example applies and indicates programmatic failures involving high safety significant SSCs, then a violation at Severity Level II should be considered).

   b. Failure to include multiple SSCs within the scope of the rule which indicates a programmatic failure to implement the requirements of the rule.

2. Severity Level IV - violations involving, for example:

   a. Failure to include an SSC within the scope of the rule.

B. Failure to establish goals for SSCs in (a)(1) or performance criteria for SSCs in (a)(2)[3]. Establishment of goals that are inconsistent with

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[1]All safety related SSCs should be clearly defined in the licensee's quality assurance program and should be identified and included within the scope of the rule.

[2]Because of the flexibility in the rule, special consideration needs to be given to determine whether a non-safety related SSC was properly excluded from the scope of the rule. 10 CFR 50.65 (b)(2) governs non-safety related SSCs. In determining whether a violation occurred, consider the reasonableness of the licensee's actions in evaluating industry-wide and plant experience and existing analyses (e.g. FSAR, IPE, etc.) to identify events that would indicate that a particular non-safety related SSC should have been included within the scope of the rule. Since licensees are not expected to consider hypothetical scenarios, it is possible that some SSCs (with no history of industry-wide and plant experience of failures) that were excluded from the scope of the rule, may fail and cause an event. The failure to include such an SSC in the scope of the rule prior to the first failure of the SSC or event would not be considered a violation. However, the licensee would be expected to include the SSC within the scope of the rule following the first failure of the SSC.

[3]The licensee has the option under (a)(2) of the rule to demonstrate that the performance or condition of the SSC is being effectively controlled through the performance of appropriate preventive maintenance such that the

safety significance or industry experience, where practical, are not considered sufficient goals to meet the rule and would also be violations.

1. Severity Level III - violations involving, for example:

   a. A single failure to establish a goal for an SSC under (a)(1) or a performance criterion under (a)(2) that: 1) complicates the recovery from a plant transient or 2) in the case of high safety significant SSCs, causes a plant transient (if this example applies with more than one failure and indicates programmatic failures involving high safety significant SSCs, then a violation at Severity Level II should be considered).

   b. Multiple examples of failures to establish either goals for SSCs under (a)(1) or performance criteria under (a)(2) that indicate a programmatic failure to implement the maintenance rule.

   c. Multiple examples of the failure to take industry-wide operating experience into account when establishing goals or performance criteria, where industry-wide operating experience was readily available, that indicate a programmatic failure to meet this requirement of the rule[4].

2. Severity Level IV - violations involving, for example:

   a. A single failure to establish a goal for any SSC under (a)(1) or a performance criterion for any SSC under (a)(2).

C. Failure to establish a monitoring program (this would include the failure to take timely and appropriate corrective action in the evaluation of monitoring activities) that adequately supports the goals set under 10 CFR 50.65 (a)(1) or the performance criteria set under 10 CFR 50.65(a)(2). The monitoring program must be sufficient in scope and

---

SSC remains capable of performing its intended function. NUMARC 93-01 uses the establishment of performance criteria to accomplish this. The licensee also has the option of not establishing goals or performance criteria if a determination is made that low safety significant SSCs are inherently reliable or could be allowed to run to failure. However this determination must be made and documented in advance of the failure.

[4]Evidence that industry-wide operating experience was taken into consideration is not required for every goal. However, if multiple examples of goals and performance criteria are reviewed where industry-wide operating experiences are readily available and examples are not found where the licensee can demonstrate that they were taken into consideration, then the licensee's program indicates a programmatic failure.

frequency to adequately support a determination as to whether SSCs are meeting their assigned goals or performance criteria.

1. Severity Level III - violations involving, for example:

    a. A single failure to establish a monitoring program that adequately supports a goal set under (a)(1) or a performance criterion under (a)(2) that: 1) complicates the recovery from a plant transient or 2) in the case of high safety significant SSCs, causes a plant transient (if this example applies with more than one failure and indicates programmatic failures involving high safety significant SSCs, then a violation at Severity Level II should be considered).

    b. Multiple failures to establish a monitoring program that adequately supports a goal set under (a)(1) or a performance criterion under (a)(2) that indicate a programmatic failure to implement the requirements of the maintenance rule.

    c. A failure to establish a monitoring program that adequately supports a goal set under (a)(1) or a performance criterion under (a)(2) that results in repetitive maintenance preventable functional failures (MPFFs)[5].

2. Severity Level IV - violations involving, for example:

    a. A single failure to establish a monitoring program that adequately supports a goal set under (a)(1) or a performance criterion under (a)(2).

D. Failure to take timely and appropriate corrective action (this would include evaluation of monitoring activities) when a goal or performance criterion is exceeded. Repetitive failures due to inappropriate or ineffective corrective action could be considered a violation under this rule for all SSCs within the scope of this rule or a violation of 10 CFR 50 Appendix B for safety-related SSCs.

1. Severity Level III - violations involving, for example:

    a. A single failure to take timely and appropriate corrective action when a goal or performance criterion for an SSC is exceeded (failed) which 1) complicates the recovery from a plant transient or 2) in the case of high safety significant

---

[5] Maintenance Preventible Functional Failures (MPFFs) are defined in NUMARC 93-01, Appendix B, as the failure of an SSC within the scope of the Maintenance Rule to perform its intended function, where the cause of the failure of the SSC is attributable to a maintenance-related activity. The staff has endorsed the use of MPFFs as a tool for monitoring SSC maintenance performance in Revision 1 of Regulatory Guide 1.160 (January 1995).

SSCs, causes a plant transient (if this example applies and indicates programmatic failures involving high safety significant SSCs, then a violation at Severity Level II should be considered).

b. The failure to evaluate the results of monitoring activities which results in repetitive MPFFs.

c. Multiple failures to take timely and appropriate corrective action when a goal or performance criterion is exceeded (failed) that indicates a programmatic failure to implement the requirements of the maintenance rule.

2. Severity Level IV - violations involving, for example:

a. A single failure to take timely and appropriate corrective action when a goal or performance criterion is exceeded (failed).

E. Failure to make a reasonable effort to identify and determine the cause of MPFFs of SSCs covered under (a)(2) would be a violation. Failure to develop a rationale or justification for continuing to cover an SSC under (a)(2) after it has experienced a repetitive MPFF would be a violation.

1. Severity Level III - violations involving, for example:

a. Multiple failures to make a reasonable effort to determine the cause of MPFFs of SSCs covered under (a)(2).

b. Multiple failures to develop a rationale or justification for continuing to cover these SSCs under (a)(2) after they have experienced a repetitive MPFFs that indicate the programmatic failure to implement the requirements of the rule.

2. Severity Level IV - violations involving, for example:

a. A single failure to make a reasonable effort to determine the cause of a MPFF of an SSC covered under (a)(2).

b. The failure to develop a rationale or justification for continuing to cover that SSC under (a)(2) after it has experienced a repetitive MPFF.

F. Failure to perform the required periodic assessment for the activities described under (a)(3) would be a violation.

1. Severity Level III - violations involving, for example:

   a. The failure to perform any required periodic assessment which indicated a programmatic failure to meet the requirement of the rule.

2. Severity Level IV - violations involving, for example:

   a. The failure to include a review of performance and monitoring activities and associated goals and preventive maintenance activities (i.e., all (a)(1) and (a)(2) activities) in the periodic assessment.

   b. Completing this assessment in an untimely manner[6].

   c. The failure to take industry-wide operating experience into consideration when performing the periodic assessment.

G. Failure to periodically (once per refueling cycle, not to exceed 24 months between evaluations) balance reliability and unavailability due to monitoring/maintenance activities would be a Severity Level IV violation.

H. A failure to develop, implement or adhere to any of the procedures developed by a licensee to implement the rule may be a violation and could be assessed as a violation of the licensee's technical specifications or 10 CFR 50 Appendix B.

1. Severity Level III - violations involving, for example:

   a. A single failure to develop or follow procedures involving the maintenance of an SSC that 1) complicates the recovery from a plant transient or 2) in the case of high safety significant SSCs, causes a plant transient (if this example applies and indicates programmatic failures involving high safety significant SSCs, then a violation at Severity Level II should be considered).

   b. The failure to develop or follow procedures that results in repetitive MPFFs.

   c. Multiple examples of failures to develop or follow procedures that indicate a programmatic failure to implement the requirements of the maintenance rule.

2. Severity Level IV - violations involving, for example:

   a. A single failure to develop or follow procedures.

---

[6]At least one assessment during each refueling cycle provided the interval between assessments does not exceed 24 months.

II. Examples of Activities That Would Not Necessarily Be Violations of the Maintenance Rule:

A. A failure to meet a licensee developed goal under (a)(1) would not be subject to enforcement action as long as appropriate corrective action had been taken when the goal was not met.

B. It is intended that licensees be allowed flexibility when establishing goals and not be subject to enforcement on goal selection as long as these goals are reasonably based on safety and industry operating experience. The NRC does not intend to second guess the details of these goals. However, the NRC will review these goals to ensure that they are reasonably based on safety and industry operating experience.

C. The details of the monitoring program would not be subject to enforcement action as long as the monitoring was sufficient to adequately support the goals and provided for an evaluation whenever a goal was exceeded (See example of violations C and D above).

D. Since the rule states that, in performing monitoring and preventive maintenance activities, an assessment of the total plant equipment that is out of service should be taken into account to determine the overall effect on performance of safety functions, the failure to perform this assessment would not be a violation of 10 CFR 50.65(a)(3). However, licensees are expected to perform this assessment.

If the inspector finds that a licensee is not performing this assessment using the methods detailed in NUMARC 93-01, Section 11, or equivalent methods, then the inspector should consider this to be an issue that should be referred for resolution to NRC management and the Maintenance Rule Enforcement Review Panel, established by EGM 96-001.

In a case where this failure to perform a safety assessment contributed to the severity of another violation of the regulations, or exacerbated the consequences of an event or transient, the failure to perform a safety assessment could be taken into account as an escalating factor in any escalated enforcement action.

In addition, the failure to consider the overall impact of taking equipment out of service that: (1) exhibits a pattern supporting a programmatic issue, (2) causes the initiation of a plant trip or a transient with the potential for a trip, or (3) demonstrates the potential for a high risk system configuration is of significant regulatory concern and should be considered for enforcement action. Depending on the circumstances, the enforcement related action (enforcement conference, Demand for Information, Order, etc.) should be utilized to focus the licensee on the need to modify its maintenance activities because of its demonstrated failure to consider the overall safety impact of removing equipment from service.

E. Deficiencies in records and documentation would not in themselves be subject to enforcement. However, if they contribute to an inappropriate action or inaction to correct the performance of an SSC, these record or documentation deficiencies may be cited as contributing factors in an enforcement action.

Multiple Addressees

DISTRIBUTION:
JLieberman, OE
OE Staff
Enforcement Coordinators
RI, RII, RIII, RIV
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8/20/96	~~8/ /96~~	8/20/96	8/20/96

Doc Name: G:\M-EGM2R6.MS

TAB H

MAINTENANCE RULE COORDINATOR REVIEW/QUESTION SHEET

Maintenance Rule Coordinator Questions

Inspector: ______________________

Licensee's Maintenance Rule Coordinator(s): ______________________

____

Interview the maintenance rule coordinator to get a basic understanding of the process and procedures the licensee used to implement the rule. Ask the following questions:

___ 1. How have you educated the appropriate plant staff regarding the requirements of the maintenance rule.

___ 2. Does your management adequately support the implementation of the rule?

___ 3. How are repeat failures identified?

___ 4. How are repeat MPFFs identified?

___ 5. What actions are taken after they are identified?

___ 6. How are generic implications taken into consideration?

___ 7. Are the persons responsible for implementing the rule clearly defined?

___ 8. Was NUMARC 93-01 followed when implementing the rule?

___ 9. Are there any exceptions?

___ 10. What SSCs are under the scope of the rule?

___ 11. How are systems and trains defined?

___ 12. How did you determine which systems were risk significant?

___ 13. How did you determine which structures were risk significant?

___ 14. Which are being monitored at the plant, system, train, or component level?

___ 15. Which are being monitored under (a)(1) of the rule?

___ 16. How did you determine which SSCs should be monitored using goals under (a)(1) of the rule.

___ 17. How is unavailability data recorded?

___ 18. Is trending performed for all systems?

___ 19. Who is responsible for trending?

___ 20. Has your Plant identified SSCs that have been determined to be allowed to run to failure or that are inherently reliable?

___ 21. How are these determinations documented?

___ 22. What is your process for establishing performance criteria for SSCs within the scope of the rule.

___ 23. How is industry-wide operating experience used to support the rule in the areas of Implementation and day-to-day operation.

___ 24. Which SSCs are being monitored using plant level performance criteria?

___ 25. How was the decision made to use plant level performance criteria?

___ 26. What action is taken when a plant level performance criterion is exceeded?

___ 27. Who has responsibility for evaluating failures and establishing corrective actions?

___ 28. Was past performance taken into consideration when establishing performance criteria?

___ 29. Where you able to obtain reliability and unavailability and failure data for the previous two cycles?

___ 30. What process is used ensure that the scoping list is maintained up-to-date (EOP changes, design changes, SCRAMS, etc.)?

___ 31. Has specific training been given to those on the expert panel and those responsible for performance monitoring and trending, making (a)(1)(a)(2) determinations, and other rule activities?

TAB I

EXPERT PANEL REVIEW/QUESTION SHEET

Expert Panel Questions

Inspector: ___________________________

Interview the expert panel to determine if the licensee is using the risk determination methods described NUMARC 93-01 to satisfy the requirements of (a)(1) and (a)(2) of the maintenance rule. If so, review the implementation to determine if it is in accordance with the methods described in paragraph 9.3.1 of NUMARC 93-01. Additional guidance is provided in IP 62706, general guidance section "Safety Determination" and specific guidance section 03.01.b.1. During this review ask the following questions:

✓ 1. Has an expert panel been established?

___ 2. List the names, titles, and discuss qualifications of expert panel members. (Members should have expertise in operations, maintenance, engineering. Inspector should determine whether or not the expert panel had appropriate expertise)

✓ 3. Was a PRA expert included as a member of the expert panel?

___ 4. Is there an expert panel charter or procedure that describes their duties and responsibilities.

___ 5. If the expert panel is permanent, are there provisions for assuring that the required level of expertise is maintained when replacing members?

___ 6. If the expert panel is not permanent, how will future plant modifications be handled?

___ 7. What activities besides risk ranking (scoping, performance evaluation, etc.) are the expert panel members involved in?

? 8. Were you trained on the use of PRA information and its limitations?

✓ 9. What are some of the limitations of the use of PRA? (The inspector should try to make a evaluation of how well the expert panel understands PRA)

✓ 10. Were Risk Reduction Worth, Core Damage Frequency Contribution, Risk Achievement Worth methods used for determining risk when establishing goals under (a)(1) or performance criteria under (a)(2) of the rule?

___ 11. Were risk considerations other than PRA used? (The inspector should make a determination as to whether this method is adequate for purposes of the maintenance rule).

___ 12. How were systems not modeled by PRA determined to be risk significant?

___ 13. Were there differences between what was considered PRA risk significant and Expert Panel risk significant?

___ 14. Is the reliability and availability data obtained through the maintenance rule monitoring activities being used to update or evaluated against the assumptions used in the PRA?

___ 15. Were any additional insights used by the expert panel to determine risk significance of SSCs?

___ 16. Does the selection of risk significant SSCs seem reasonable? (After discussing this with the expert panel, the inspector should independently assess the adequacy of the risk determination process).

TAB J

SCOPE OF RULE 50.65(b) REVIEW/QUESTION SHEET

(b) Scope of the Rule Review

Inspector: ____________________

The inspector should independently select a sample from each of the following categories and verify that the licensee has included them within the scope of the maintenance rule. See IP 62706 step 02.04 and the guidance provided in section 03.04.

1. Safety-related SSCs

2. Non-safety-related SSCs:

   That are relied upon to mitigate accidents or transients;

   That are used in EOPs have been included;

   Whose failure could prevent safety-related SSCs from fulfilling their intended function;

   Whose failure could cause a scram or actuation of a safety system;

The inspectors should ask the maintenance rule coordinator to explain any SSCs which were excluded from the scope of the rule.

TAB K

PERIODIC REVIEW AND BALANCING 50.65(a)(3) REVIEW/QUESTION SHEET

(a)(3) Periodic Evaluation and Balancing Questions

Inspector: ____________________

The inspectors should review any evaluations that have already been performed and the licensee's procedures for controlling this activity. Then the inspector should interview the persons responsible for performing the periodic evaluation and balancing reliability and unavailability and ask the following questions. See IP 62706 steps 02.03.a and b and the guidance provided in section 03.03.a. and b.

___ 1. What is your schedule for performing these evaluations? (the rule requires that the evaluation be performed at least every refueling cycle provided the interval does not exceed 24 months between evaluations)

___ 2. Does the periodic evaluation (or do the plans for the periodic evaluation) include an assessment of performance and condition monitoring activities and associated goals and preventive maintenance activities?

___ 3. Does the periodic evaluation (or do the plans for the periodic evaluation) take into account, where practical, industry-wide operating experience?

___ 4. What process have you established for making adjustments where necessary to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs because of monitoring or preventive maintenance activities? (the inspector should briefly describe the method and make a determination as to whether it meets the intent of the rule).

___ 5. Are there any examples where this activity resulted in changes to the preventive maintenance activities for specific SSCs?

___ 6. Who will be performing the evaluation?

___ 7. Who in plant management will review the evaluation?

TAB L

ASSESS SAFETY IMPACT OF TAKING SSCs OUT OF SERVICE 50.65(a)(3) REVIEW/QUESTION SHEET

(a)(3) Safety Assessment Questions

Inspector: ____________________

Review the licensee's process and procedures for determining if the licensee has implemented a method for performing this safety assessment in accordance the guidance contained in NUMARC 93-01, section 11, including: identification of key plant safety functions, identification of SSCs that support key plant safety functions, and assessment and control of the effect of the removal of SSCs for service on those key plant safety functions. See IP 62706 step 02.03.c. and the guidance provided in section 03.03.c.

___ 1. Interview the maintenance rule coordinator and ask him to explain the processes that the that are used to control this activity.

___ 2. Interview the PRA expert and ask him to explain how PRA information is used to make these safety assessments.

___ 3. What types of computer programs or calculational methods were used to perform these safety assessments?

___ 4. Interview planners and schedulers and ask them to explain their understanding of the rule and their particular role in performing these safety assessments.

___ 5. Interview maintenance engineers and ask them to explain their understanding of the rule and their role in performing these safety assessments.

TAB M

PLANT OPERATOR REVIEW/QUESTION SHEET

Plant Operator Questions

Inspector: ______________________________

Interview the plant operators and ask the following questions:

__ 1. Can you describe the key requirements of the Maintenance Rule.

__ 2. What maintenance rule activities are you responsible for? (preforming safety assessments before taking SSCs out of service, keeping track of unavailability times?, etc.)

__ 3. When do you declare a SSC out of service and who is responsible for making that determination?

__ 4. How is unavailability data for maintenance rule systems recorded?

__ 5. Which systems is this data recorded for?

__ 6. What purposes is this information used for under the maintenance rule?

__ 7. What is a PRA is and how it is used for implementing the maintenance rule?

__ 8. How is risk assessed prior to performing monitoring or preventive maintenance at your plant?

__ 9. Are you involved in this process?

__ 10. How can you determine which SSCs are out of service at any given time.

__ 11. How can you determine which SSCs are within the scope of the rule?

__ 12. How can you determine which SSCs are risk significant?

TAB N

GOAL SETTING AND MONITORING 50.65(a)(1) REVIEW/QUESTION SHEET

(a)(1) Goal Setting and Monitoring Questions

For Selected SSC: ____________________ Inspector: ____________________

Select an SSC for review from those the licensee has identified as being handled under (a)(1) of the rule. Include in this sample some SSCs that were dispositioned from (a)(2) to (a)(1). Also attempt to include some SSCs that have been identified in the licensee's operating experience program. See IP 62706 step 02.01 and associated specific guidance in section 03.01. Interview the system engineer and ask the following questions. Record the answers and any concerns.

___ 1. What goals were set and what monitoring was being performed? Was this monitoring activity part of an existing program?

___ 2. If the system is risk significant, are both reliability and availability being monitored?

___ 3. What was the basis for determining it to be (a)(1)?

___ 4. Was plant management involved in the decision?

___ 5. How will you know when it can be reclassified as (a)(2)?

___ 6. How was safety (or risk) taken into consideration when establishing goals and monitoring against those goals?

___ 7. Did you have any input into the risk determination process?

___ 8. Why is the SSC being monitored at the (plant, system, train, component) level? (the inspector should make an independent determination as whether the SSC is being monitored at the appropriate level)

___ 9. Is monitoring predictive in nature and is trending being performed?

___ 10. Was industry-wide operating experience taken into account when establishing these goals?

___ 11. How did this goal address the cause of the repetitive failure or the reason for exceeding its (a)(2) performance criteria?

___ 12. Did this SSCs experience any maintenance preventible functional failures or exceed an established goal?

___ 13. What was the root cause? (the inspector should make an independent assessment of the adequacy of the root cause determination)

___ 14. What corrective action was taken? (The inspector should make an independent determination of the adequacy of the corrective action)

___ 15. Was the effectiveness of corrective action verified either by post maintenance testing or modification of goals or monitoring activities?

___ 16. What are your (the system engineers) background and qualifications?

___ 17. Describe your understanding of the Maintenance rule.

___ 18. What is the difference between a performance criterion and a goal?

___ 19. What is the purpose of establishing a goal?

___ 20. Do you feel that your management would hold it against you for placing your system into (a)(1)?

___ 21. How do you view (a)(1) classifications?

___ 22. How do you determine when to place an SSC into (a)(1)?

___ 23. What role did you play in establishing the goals for your system(s)?

___ 24. Do you understand the basis for the goals for your system?

___ 25. Do you agree with the goals that were established?

___ 26. What maintenance rule activities are you responsible for? (setting performance criteria and goals taking into account risk and industry-wide operating experience, monitoring and trending of system performance, establishing corrective action, moving from (a)(2) to (a)(1), etc?)

___ 27. Describe your system.

___ 28. How many other systems are you responsible for?

___ 29. Are the number of assigned systems changed frequently?

___ (Based in the above discussions and reviews, the inspector should make a determination whether monitoring against these goals will be sufficient to provide reasonable assurance that SSCs are capable of fulfilling their intended functions)

TAB O

PREVENTATIVE MAINTENANCE 50.65(a)(2) REVIEW/QUESTION SHEET

(a)(2) Preventive Maintenance Questions

For Selected SSC: ______________________ Inspector: ______________________

Select an SSC being handled under (a)(2) of the rule. Include in this sample SSCs that were dispositioned from (a)(1) to (a)(2). See IP 62706 section 02.02 and the guidance provided in section 03.02. Interview the system engineer and ask the following questions. Record the answers and any concerns.

___ 1. Was safety or risk taken into consideration when establishing performance criteria? Yes___No___. Explain:

___ 2. Did you have any input into the risk determination process?

___ 3. Did you make a determination that preventive maintenance was not required because the SSCs was inherently reliable? (If so, the inspector should make a determination as to whether or not this decision appears to be reasonable)

___ 4. Did you make a determination that preventive maintenance was not required for this SSC because of its low risk significance and therefore could be allowed to run to failure? (If so, the inspector should make a determination as to whether or not this decision appears to be reasonable)

___ 5. Has this SSC experienced a maintenance preventible functional failure, or failed to meet the performance criteria?

___ 6. What was the root cause? (the inspector should make an independent determination as to whether the root cause analysis was adequate)

___ 7. What corrective action was taken? (the inspectors should make an independent assessment of the adequacy of the corrective action)

___ 8. Did the licensee reconsider the performance criteria or disposition this SSC to (a)(1) where it would be subject to goal setting and monitoring.

___ 9. What type of trending is being performed? (If the SSC is risk significant. The inspector should make an independent assessment of the adequacy of this trending)

___ 10. What are your (the system engineers) background and qualifications?

___ 11. Can you describe the key requirements of the Maintenance

Rule.

___ 12. What maintenance rule activities are you responsible for? (setting performance criteria and goals taking into account risk and industry-wide operating experience, monitoring and trending of system performance, establishing corrective action, moving from (a)(2) to (a)(1), etc?)

___ 13. What is the difference between a performance criterion and a goal?

___ 14. What is the purpose of establishing a goal?

___ 15. Do you feel that placing your system into (a)(1) could have a negative impact on your personal performance appraisal?

___ 16. How do you view (a)(1) classifications?

___ 17. How do you determine when to place an SSC into (a)(1)?

___ 18. What role did you play in establishing criteria for your system(s)?

___ 19. Do you understand the basis for the performance criteria for your system?

___ 20. Do you agree with the performance criteria that were established?

___ 21. Are the performance criteria appropriate?

___ 22. For systems utilizing plant level criteria, can the systems affect the criteria?

___ 23. Describe your system

___ 24. How many other systems are you responsible for?

___ 25. Are the number of assigned systems changed frequently?

___ (Based on these discussions and reviews, the inspector should make a determination as to whether the licensee has demonstrated effective maintenance by establishing and monitoring against appropriate "performance criteria" as described in NUMARC 93-01 or other methods)

TAB P

EMERGENCY DIESEL GENERATOR REVIEW/QUESTION SHEET

Emergency Diesel Generator Questions

Inspector: ________________

Verify that the maintenance program for emergency diesel generators satisfies the commitments made by the licensee in response to 10 CFR 50.63, Station Blackout Rule. The inspector should ask the maintenance rule coordinator or the EDG system engineer the following questions. See IP 62706 step 02.05 and the guidance contained in section 03.05. (Note that this review is in addition to the reviews performed using the (a)(1) or (a)(2) checklists.)

___ 1. Have target reliability values or other alternate commitments made in response to the station blackout rule been incorporated into the maintenance program either as goals or performance criteria?

___ 2. How have these commitments been implemented.

TAB R

RISK INSPECTION GUIDANCE

* DRAFT - FOR INFORMATION ONLY *

SUPPLEMENTAL MAINTENANCE RULE BASELINE INSPECTION GUIDANCE REGARDING LICENSEE USE OF PRA FOR RULE IMPLEMENTATION

We expect that most licensees will use PRA based approaches to implement certain parts of the maintenance rule. Due to the variation of PRA methodologies used by licensees, the baseline inspections must be performed by personnel with the proper background and training.

The purpose of this supplemental guidance is to provide additional information to the PRA specialist who is performing the inspection of the licensee's use of their PRA for implementing the maintenance rule. This guidance should be used in conjunction with inspection procedure (IP) 62706, "Maintenance Rule."

This proposed supplemental guidance is intended to be refined as the baseline Maintenance Rule implementation inspections are conducted. Comments and suggestions for improvement should be sent to P. Wilson or J. Shackelford, NRR, SPSB.

INSPECTION OBJECTIVES

For licensees that have elected to utilize PRA in the implementation of certain parts of the Maintenance Rule, the following are inspection objectives to be accomplished during the base-line inspections.

Inspection Objective 1. Determine if a licensee has adequately established the safety significance of structures, systems, and components (SSCs) covered by the rule.

Inspection Objective 2. Determine if a licensee has adequately set performance goals and performance criteria under (a)(1) and (a)(2) of the rule (respectively), consistent with the assumptions used to establish the safety significance.

Inspection Objective 3. Determine if a licensee is using a rational approach to balance SSC unavailability for monitoring or preventive maintenance activities with the intended improvement in SSC reliability.

Inspection Objective 4. Determine if a licensee has adequately assessed the overall effect on the performance of safety functions when SSCs are removed from service for monitoring or preventive maintenance.

INSPECTION GUIDANCE

General Guidance

Inspection Requirements. The NRC's inspection requirements are listed in Section 02 of IP 62706. However, inspectors should also note that while some items are listed under the inspection requirements, they may not be explicitly stated in the maintenance rule. Rather, these items may be derived from Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," or NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which are optional and, therefore, would not apply to those licensees who implement the rule using other methods.

Implementation Guidance. Except when the licensee proposes an alternate method for complying with specified portions of the rule, the methods described in Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," will be used to evaluate the activities of licensees who are required to comply with the maintenance rule. This regulatory guide endorses NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and provides methods acceptable to the NRC for complying with the maintenance rule. The inspector should become familiar with Regulatory Guide 1.160 and NUMARC 93-01 before initiating this inspection. The inspector should also be aware that licensees may use methods other than those described in Regulatory Guide 1.160 and NUMARC 93-01 to satisfy the requirements of the maintenance rule. Where other methods are used, the licensee must demonstrate that those methods satisfy the requirements of the rule. Where a licensee implements the rule partly in accordance with Regulatory Guide 1.160 and NUMARC 93-01, and partly in accordance with other methods, the licensee must demonstrate that those other methods meet the applicable parts of the rule.

During the pilot site visits the NRC review team noted that the guidance contained in NUMARC 93-01 was used by the licensees at all nine sites. The lessons learned from these pilot maintenance site visits are provided in NUREG 1526. Prior to conducting inspections to verify the implementation of the maintenance rule, the inspectors should be familiar with the methods used by the pilot plants, since those methods appear to meet the intent of the rule and the guidance provided in NUMARC 93-01. In addition, the inspectors should be aware that the results obtained from any PRA can be highly dependent on the plant configuration and the system reliability and availability data used to perform the calculations. Therefore, the licensees should reconsider safety-significance determinations whenever the plant design is modified, the PRA is updated, new insights become available from configuration management reviews, or new reliability and availability data become available.

Safety Determination. The rule requires that goals be established commensurate with safety. Implementation of the rule in accordance with NUMARC 93-01 requires that a safety (or risk) determination be performed for all SSCs within the scope of the rule. This safety determination would then be taken into account when setting goals and monitoring under (a)(1) of the rule and when establishing performance criteria under (a)(2). The safety determination method recommended in NUMARC 93-01 involves the use of an expert panel employing the Delphi method of NUREG/CR-5424, supplemented by Probabilistic Risk (or Safety) Assessment (PRA) or Individual Plant Evaluation (IPE) insights, to identify safety-significant SSCs.

Within the context of quantitative methods, importance measures represent an acceptable approach to the determination of safety significance. Measures such as risk reduction worth (RRW), risk achievement worth (RAW), and Fussell-Vesely (F-V)/core damage frequency (CDF) contribution have been demonstrated to provide useful information in assessing the safety significance of various SSCs. No single importance measure should be used as the sole determinant of safety significance. It is critical for the licensee to use the appropriate interpretation of the given importance measure under consideration in making safety determinations. The "risk metric" which is used is a vital determinant in the interpretation of the results. For example, importance measures which are based on CDF will not adequately convey the risk significance of SSCs involved in maintaining the integrity of the containment. A more appropriate risk metric for evaluating SSCs related to containment integrity would be that of the large early release frequency (LERF).

Importance measures, as well as other quantitative approaches are derived from some underlying analytical model. This analysis (usually a plant-specific PRA) must be technically sound in order for meaningful results to be obtained for decision making purposes. It should be noted that the NRC has not conducted reviews of sufficient depth to specifically approve any particular PRAs for this type of application. Rather, the licensee's analyses are evaluated on a case by case basis within the context of the specific application which is being considered. It is recognized that the plant PRAs/IPEs can provide a valuable source of information to be used in the maintenance process if used in a deliberate and prudent manner. The importance of the adequacy of the analysis used as the basis for quantitative decision making cannot be overstated. It is expected that the licensee be able to demonstrate to the inspector that the underlying analysis used in the safety determinations be of sufficient scope, level of detail, and quality to perform the intended functions.

During the pilot maintenance site visits, the NRC review team found that all licensees used an expert panel (or a working group) to make the safety significance determinations. These expert panels took PRA or IPE insights into consideration using the methods described in NUMARC 93-01, although there were some exceptions. NUMARC 93-01 recommends that all three methods, RRW, RAW and CDF, be calculated and provided to the expert panel for its consideration. One licensee's expert panel, inappropriately, considered only CDF and not RRW or RAW. Another licensee considered CDF and RAW but not RRW. Several licensees considered the F/V importance measure in addition to CDF, RAW, and RRW. The staff believes that the three methods described in NUMARC 93-01 (CDF, RRW, RAW) should be considered the minimum when making the risk determination unless the licensee had determined that a suitable replacement method such as F/V (or others) is used to replace one of the methods. Preliminary staff work indicates that F/V provides similar ranking information as RRW. Other methods may be developed in the future and could be used to replace either CDF, RRW, or RAW. It is recommended that licensees use at least three methods. The results of all methods used should be given to the expert panel for consideration.

<u>Safety Consideration for Goal Setting</u>. The NRC staff endorsement of NUMARC 93-01, which allows some SSCs to be monitored using plant level criteria, was based, in part, on the understanding that any repetitive component, train, or system level maintenance preventible functional failures (MPFFs) would be identified and would trigger the establishment of component, train, or system level goal setting and monitoring under (a)(1) of the maintenance rule. The rule requires licensees to establish goals commensurate with safety. Information on an SSC's contribution to plant safety can be obtained from various sources including the IPE or PRA results (if available). Section 9.0

of NUMARC 93-01 provides guidance on acceptable methods for establishing safety significance criteria. This safety determination would then be taken into account when setting goals and monitoring under (a)(1) of the rule. The safety determination method recommended in NUMARC 93-01 involves the use of an expert panel utilizing the Delphi method of NUREG/CR-5424, supplemented by PRA or IPE insights, to identify high safety significant SSCs. At a minimum, these insights should include the three methods described in NUMARC 93-01: RRW, RAW, and CDF. However, licensees may substitute other appropriate combinations of measures (e.g., Fussell/Vesely, Birnbaum) if they can provide similar risk insights. It should be recognized that if less stringent goals are established than were assumed in the IPE/PRA, then the results of the risk ranking procedure may be invalidated. The licensee should ensure, at a minimum, that performance goals are consistent with the assumptions used to derive the results for determining safety significance.

A licensee may classify some SSCs as <u>inherently reliable</u>. This provision might be used where an SSC, without preventive maintenance, has inherent reliability and availability (e.g., electrical cabling). It is expected that some structures, such as cable raceways, water storage tanks, and buildings, could be considered inherently reliable. However, it should be noted that such activities as inspections, surveys, and walkdowns could be considered maintenance activities and, therefore, most SSCs would be subject to some maintenance. Licensees should document their reasons for concluding that individual or groups of SSCs are inherently reliable. During the pilot site visits (See NUREG 1526), the inspectors noted that some licensees had made inappropriate use of this category by assuming that many structures were inherently reliable when in fact the licensees had many longstanding inspection and preventive maintenance activities already in place. The existence of these preventive maintenance activities was inconsistent with the assumption that these structures were inherently reliable.

A licensee may determine that an SSC provides little or no contribution to system safety function and may elect to allow the SSC to <u>run to failure</u>. Methods for determining safety significance are described in NUMARC 93-01, Section 9.3.3. Licensees should establish an appropriate methodology for determining safety significance and should use these criteria to identify SSCs that could be allowed to run to failure. Licensees should document these criteria and their reasons for deciding that individual SSCs could be allowed to run to failure. The inspector should evaluate the effects of the licensee's decision to allow certain SSCs to run to failure. The evaluation should include consideration of whether the decision would produce a significant affect on the overall frequency of core damage as well as whether an SSC's run to failure would affect the relative ranking of other SSCs within the scope of the rule (i.e. would allowing a given SSC to run to failure have the effect of increasing the relative importance of other SSCs such that an SSC which had been classified as LSS should in fact be classified as HSS).

<u>Balancing Unavailability and Reliability</u>. The maintenance rule requires that licensees make adjustments where necessary to ensure that the objective of preventing failures of SSCs through maintenance is appropriately balanced against the objective of minimizing unavailability of SSCs due to monitoring

or preventive maintenance activities. The intent of this requirement is to ensure that monitoring or preventive maintenance activities do not result in excessive unavailability that would negate any improvement in reliability achieved as a result of the monitoring or maintenance activity and that deferring monitoring or preventive maintenance to achieve a high availability does not result in low reliability.

Due to the fact that it might be impractical to perform this balancing on a continuous basis, licensees may establish their own schedule for performing these reviews and make any needed adjustments to their preventive maintenance activities. However, at a minimum, the licensee must perform this balancing at least every refueling cycle and include an evaluation of this activity as part of the refueling cycle evaluation process described above. This process can be qualitative, but it should be documented.

During the pilot maintenance site visits, the team reviewed the plans and procedures licensees had developed for accomplishing this activity. Two licensees planned to balance unavailability and reliability on an ongoing basis as an integral part of monitoring against performance criteria under the rule. Since performance history, preventive maintenance activities, and out-of-service time are taken into consideration when developing the performance criteria, these licensees believe that meeting these performance criteria will assure that a satisfactory balance of reliability and unavailability has been achieved. At another site, the licensee planned to accomplish this balancing by calculating the safety (or risk) contribution associated with unavailability of the system due to preventive maintenance activities and the safety contribution due to the reliability of the SSC. The licensee would then compare and attempt to balance the contribution to safety from each source to assure consistency with PRA/IPE evaluations. The NRC review team concluded that either of these methods could be a reasonable approach to satisfying this requirement of the rule. However, neither approach had been fully implemented at the time of the site visits and, therefore, could not be fully evaluated.

Additional guidance is provided in NUMARC 93-01, section 12.2.4, "Optimizing Availability and Reliability for SSCs." The inspector should note that this section limits the need to make adjustments to balance availability and reliability to those SSCs that are high safety significance.

Quantitative methods should consider the additional plant risk associated with increased SSC unavailability due to maintenance activities as well as the effects of these same maintenance activities on the reliability of the equipment and its impact on plant safety. For example, increased maintenance on a given SSC may be shown to increase the overall reliability of the equipment by some incremental factor. However, this increased maintenance may reduce the overall availability of the same SSC by some other factor. The benefits of the increased reliability due to the additional maintenance should outweigh the penalty associated with the increased unavailability in order to justify the maintenance activity on a strictly analytical basis. A complementary example would be that of increasing the availability of a given SSC by eliminating a particular maintenance activity at the expense of possibly reducing that same SSC's reliability. As before, the advantages of the increased availability should outweigh the detrimental effects of the reduced reliability in order to justify a reduction in the maintenance.

Assessment of Equipment Out of Service. In order to minimize outage time and reduce costs, many licensees are increasing the amount of preventive maintenance being performed during power operation. This can result in the simultaneous removal of multiple systems from service, which can result in significant increases in risk during these periods. The NRC is concerned that some licensees may not be adequately analyzing the risk or safety impact associated with these unavailabilities. The failure to adequately evaluate safety when planning and scheduling maintenance has led to simultaneous unavailabilities of multiple redundant or diverse systems at some sites, possibly leading to undesirable increases in risk despite the fact that such configurations may not be prohibited by technical specifications. The technical specifications for most sites were crafted for random failures; voluntary removal of multiple systems from service may not be bounded by worst case single failure assumptions in technical specifications. The NRC is concerned that risk can significantly increase during periods when multiple redundant or diverse systems are unavailable due to preventive maintenance.

The maintenance rule addresses both on-line and shutdown maintenance. Under paragraph (a)(3) of the Maintenance Rule, the NRC expects licensees to assess the total impact on plant safety before taking plant equipment out of service for monitoring or preventive maintenance. This assessment is to be performed on an ongoing basis, not just during the periodic assessment performed during every refueling cycle. Additionally, this assessment is not intended to be limited to situations whereby the equipment is fully removed from service. Rather, it is expected that the assessments will cover all maintenance activities on SSCs within the scope of the rule regardless of whether the equipment is actually removed from service during the maintenance task. This ongoing assessment should be performed regardless of plant mode, i.e., whether the plant is operating or shutdown. As stated in the SOC, assessing the cumulative impact of out-of-service equipment on the performance of safety functions is intended to ensure that the plant is not placed in safety (or risk) significant configurations. These assessments do not necessarily require that a quantitative assessment of probabilistic safety be performed. However the PRA or IPE may provide useful information on safety significance of various SSCs. The level of sophistication with which such assessments are performed is expected to vary. These assessments may range anywhere from a simple matrix based on qualitative and quantitative risk insights to the use of an on-line living PRA or risk monitor. It is expected that, over time, assessments of this type will be refined as the technology improves and experience is gained. In order to accomplish these assessments, licensees must keep track of the status (in or out of service) of plant equipment. This status may be kept as a manual list or on a database but must be easily accessible and kept up to date. In order to be useful and accessible the information should be kept in one location and not scattered among several documents (shift logs, status boards, tag out status boards) in various locations. Additional guidance is provided in section 11.0 of NUMARC 93-01.

During the pilot maintenance site visits, the NRC review team found that licensees planned to use, or had used, a variety of approaches for assessing the overall effect on the performance of safety functions of taking plant equipment out of service for monitoring or preventive maintenance. It appeared that industry is developing a heightened awareness of the importance of managing the risk of performing maintenance during power operation. As stated above, the licensee's assessment of the effects of monitoring and maintenance activities may be either quantitative or qualitative. Where quantitative methods are used, the inspector should verify that the analytical basis for the quantification (most likely a plant specific PRA or IPE) is of appropriate scope and quality to support the assessments. The same considerations which were used in evaluating the fidelity of the analysis for determining safety significance also apply in evaluating total equipment out-of-service assessments.

The specific format of the quantitative assessments used by licensees may vary. However, the end result of the assessment should provide information as to the effects of individual maintenance configurations on plant risk. The specific measure of plant risk being considered should be clearly defined (i.e. core damage frequency, large early release frequency, etc.) In this respect, certain approaches have been shown to exhibit unique strengths and weaknesses which are specific to the approach which has been used. The assessment should consider the risk impact associated with the proposed maintenance activities from SSCs used to mitigate events as well as the risk impact from SSCs that are considered to be event initiators (i.e. scheduling switchyard maintenance during an emergency diesel outage).

The most detailed approach consists of actual quantification of the proposed maintenance configurations using a full plant PRA model or "risk monitor". Tools of this type are able to analyze a wide variety of unique plant configurations. If this approach is used, the overall adequacy of the assessment will be a function of both the fidelity of the underlying PRA model used in the quantification as well as the accuracy of the input assumptions regarding the availability of the equipment being considered for maintenance. Since fast running PRA models have sometimes been simplified or optimized, the inspector should review the licensee's process which has been used to validate the adequacy of the optimized model. (i.e. The inspector should apply the same considerations which were used in evaluating the risk ranking results in order to ensure that the model accurately reflects plant configurations.) In addition, particular attention should be directed towards situations where the proposed maintenance activities affect SSCs with differing safety functions. For example, maintenance on ECCS systems concurrently with containment systems would reduce plant protection at two different levels (i.e. both accident mitigation and containment performance). If the underlying analytical tool does not accurately model containment performance, then the output of such an analysis may significantly underestimate the total plant risk.

Another analytical approach which has been used is that of a matrix of pre-analyzed plant configurations. An approach such as this attempts to define acceptable maintenance configurations with the goal of reducing the analytical burden of real-time calculations. When this type of approach is used, the inspector should verify the technical adequacy of the matrix. It should be realized that this approach is limited in the number of allowable configurations which can be considered. It is possible that situations will arise whereby unexpected failures will occur of other SSCs within the scope of the rule after the licensee has entered an allowed configuration as specified by the matrix approach. This new configuration would then be outside of the scope of the pre-analyzed condition. (i.e. The additional equipment out of service caused by the failure in conjunction with the equipment outages specified by the matrix have not been previously analyzed.) The inspector should determine what methods the licensee employs to determine the acceptability of the emergent condition and what contingency measures are in place to maintain plant risk at an acceptable level during such situations. At a minimum, the inspector should verify that the licensee has a program in place which will ensure that key plant safety functions are maintained even when the resultant configurations exceed the boundaries of the pre-analyzed configurations.

<u>State of the Art PRA Attributes</u>

a. <u>Scope of Analysis</u>. Where quantitative results are used, the inspector should verify that the underlying analysis is of sufficient <u>scope</u> to incorporate all of the necessary SSCs. For example, a typical "Level 1" PRA would not include SSCs related solely to containment integrity. Thus, reliance on such an analysis would overlook the important SSCs related to the containment. Similarly, systems related to spent fuel pool cooling and radwaste systems are not typically addressed in such an analysis. Some important plant systems may only be applicable to shutdown configurations and as such would not be addressed by typical PRAs. (Most PRAs assume that the plant is initially at full power.) The inspector should examine the scope of the underlying analysis to determine the extent to which the plant has been modelled. The scope of the maintenance rule extends to a variety of SSCs which are not commonly modelled in traditional PRA studies. The inspector should evaluate the methods by which the licensee incorporates known limitations of the scope of the analysis to ensure that important SSCs are not misclassified during the importance ranking process. The total reliance on an analysis of limited scope would not represent an acceptable approach to risk based decision support. Where it has been shown that the underlying analysis is not of sufficient scope to incorporate all of the relevant SSCs into the ranking process, the licensee should demonstrate that an expert panel process has adequately addressed the deficiencies.

b. <u>Level of Detail</u>. The licensee's quantitative analysis must be of sufficient <u>detail</u> to support decisions regarding safety determinations. Obviously, SSCs which are not modelled in the PRA will not show up as "important" during risk ranking calculations. The modelling of SSCs with respect to component boundaries can be an important determinant in assessing the level of detail of the analysis. One important issue which has been identified in the past is that of whether the electrical power breakers are included within the component boundaries for individual pieces of equipment. Similarly, certain auxiliary equipment (i.e. cooling fans, lube oil pumps, etc.) is often subsumed within the component boundary of larger components. Many complex systems are commonly modelled as super components or "black boxes" in PRA studies.

(i.e. diesel generators, certain relay/logic switching circuits, turbine trip systems, etc.) If the licensee's implementation of the maintenance rule does not address the individual SSCs in a manner consistent with the treatment observed in the quantitative analysis, inappropriate decisions may result. The inspector should verify that the level of detail associated with the analysis is appropriate to support the types of decisions which are being made. In those areas where the level of detail of the analysis may not be sufficient, the licensee's expert panel process should address the deficiencies.

c. Quality of Analysis. The overall quality of the PRA must be adequate if it is to be used to support quantitative decisions of safety significance. In this context, quality refers to various attributes of the data, assumptions, and the methodology which has been used, as well as consistency of the results. Additionally, the PRA should have been subjected to some type of formal review process. Ideally, the review process should include both internal and external peer reviews. Also, a comparison of other studies based on similar plant designs should be conducted. Any significant deviations between the comparison study and the licensee's PRA should be fully addressed. The inspectors should review the licensee's documentation which relates to the resolution of these types of discrepancies.

With respect to data, the analysis should reflect plant-specific information to the maximum extent practicable. This data should be subjected to periodic reviews by the licensee and updated on a periodic and as-needed basis. The data used to support reliability and availability estimates should be of sufficient fidelity to provide meaningful results. (i.e. The data should be derived from valid operational and test results when such data is available. The meaningfulness of a given result is dependent upon the number of observations used to derive the estimate.) The inspector should evaluate the empirical basis for the licensee's reliability and availability estimates to determine if the supporting information reflects actual observed operational experience. (i.e. the inspector should select a sample of SSCs and compare the assumed estimates with actual plant records to determine whether the assumptions are consistent with actual observations). Inspectors are not expected to perform actual statistical estimations of component reliability. Rather, inspectors should ensure that the licensee's performance goals and criteria are not inconsistent with observed equipment performance from a qualitative perspective (i.e. it would be inappropriate to make reliability estimates on the basis of limited component demand data). However, inspectors can make quantitative comparisons between the licensee's availability goals and criteria and actual observed equipment outage times (i.e. compare actual observed unavailability hours with that which was assumed in the PRA).

The data should also reflect industry operating experience when it has been shown that such input would provide additional value to the analysis. (i.e. Have other similar facilities experienced operational difficulties that would be applicable to the licensee.) LERs, SOERs, vendor correspondence, and other information which provides insight into SSC failure and reliability considerations should be incorporated by the licensee.

PRAs generally assume that maintenance outages of equipment occur randomly and, therefore, overlaps of equipment outages that can cause changes in the relative importances are also random. Actual plant-specific maintenance practices, such as rolling periodic on-line maintenance schedules can introduce systemic effects that result in more or less overlap of equipment outages. This could result in importance rankings that are different from those that would exist if these systemic effects were not present. Whether this results in an increase or decrease in the actual importance level of any particular component compared to that estimated by the PRA (which assumed that the outages are random) depends on the licensee's sensitivity to avoiding concurrent outages of pieces of equipment that would substantially increase the accident frequency. If actual maintenance practices are different from those modeled in the PRA, this information must be presented to the panel along with an assessment of the potential impact of these differences on the relative risk importance rankings derived from the PRA.

The basic assumptions used in the PRA can affect the output of the quantitative decision making process. The PRA should be based on realistic, best estimate assumptions and data. Overly conservative assumptions can lead to the elevation of the importance of certain SSCs at the expense of masking the true importance of others. (i.e. A given success criteria which specifies that 2 out of 3 pumps be available when in fact only 1 pump is required would represent an unnecessary conservatism. This could cause importance measures associated with the pumps to be artificially higher, possibly at the expense of masking the importance of other components. Similarly, erroneous assumptions regarding the reliability or maintenance unavailability of components can also skew the results.) The assumptions which are used to form the basis for the model should be derived from a sound engineering or deterministic basis. The inspector should verify that the licensee has sufficient justification to support the thermal-hydraulic and/or statistical basis for the important assumptions.

d. Uncertainty. It is recognized that any decision making process based on probabilisitic considerations is necessarily subject to a degree of uncertainty. Various aspects of the process have a higher degree of uncertainty than others. In particular, very rare events such as seismic events, or situations involving human error and recovery actions can be shown to exhibit larger uncertainty characteristics. Uncertainties can generally be dealt with by the use of sensitivity studies and the use of the expert panel. Re-ranking based on 95th and 5th percentile values will point out events that might have to be moved up in importance because their relative uncertainty bands are large. If grouping of components is done correctly, the width of the risk importance classes should accommodate PRA uncertainties. The low ranked components should not be overly sensitive to PRA uncertainties. The licensee's expert panel process should address considerations of uncertainty in the decision making process when using quantitative methods.

e. Truncation. In quantifying the PRA, truncation of low frequency events is usually performed. The truncation limit should be chosen such that it is low enough that there is evidence of convergence towards a stable result. To ensure that insights (importance measures, sensitivities, etc.) are not affected by truncated events and sequences, cutoff values that are at least four orders of magnitude lower than the final CDF have been suggested (this usually means cutoff values of around 1E-9). Some studies suggest even smaller values at 1E-11 to 1E-14.

It should be noted that with the current PRA software and current computers, cutoffs at 1E-11 are quite easily achieved. However, many licensees still do the sequence "recovery " manually, and using a 1E-11 cutoff would significantly increase the effort involved this task.

The inspector should evaluate the truncation limit imposed by the licensee on the PRA results. When cutoffs higher than 1E-9 are used, results should be carefully reviewed. Ideally, the licensee should perform sensitivity studies to show that conclusions will not be affected when truncation limits are raised. However, it should also be noted that some PRAs modularize to a great extent. If this is the case, the inspector should realize that a 1E-9 limit might actually be closer to a 1E-11 limit once de-modularization is done.

Stating that the truncation value chosen will ensure 95% of the CDF is captured is generally not sufficient. The licensee should demonstrate that a sufficient amount of cutsets have been retained to ensure that correct insights can be generated, (i.e., we need to ensure that a few dominant sequences cannot hide the contribution of other potentially important sequences). Therefore, the truncation value has to be chosen together with the pertinent decision criteria (e.g. F.V > 0.005 or RAW > 2) to ensure total risk coverage.

Expert Panel. The licensee's quantitative decision making process should be complementary to deterministic methodology. PRA technology is subject to certain limitations related to modeling, data, and quality as described above. While the results of a high quality, PRA-based process can provide meaningful input into technical decision making, it is the ultimate responsibility of the licensee to verify and validate the results of this methodology. The outputs of the quantitative decision making process must be subjected to an expert review to ensure that a proper integration of deterministic and probabilistic insights has been achieved. The expert panel should have the final say in making the determinations as to the safety significance of the individual SSCs. NUMARC 93-01 provides general guidance as to the conduct and composition of an expert panel. The inspector should verify that the expert panel is composed of individuals with a background in operations, maintenance and PRA technology. The panel should exhibit a structured approach to decision making such that when the composition of the panel changes periodically, consistent decision outputs will be achieved. (i.e. The panel's decisions should be similar even when the panel is comprised of different individuals.) The panel's decision making process must be defined and documented in such a way that it is both scrutable and reproducible. The licensee should be able to demonstrate the rationale behind the decision making guidelines which are used by the panel. PRAs generally assume that maintenance outages of equipment occur randomly and, therefore, overlaps of equipment outages that can cause changes in the relative importances are also random. Actual plant-specific maintenance practices, such as rolling periodic on-line maintenance schedules can introduce systemic effects that result in more or less overlap of equipment outages. This could result in importance rankings that are different from those that would exist if these systemic effects were not present. Whether this results in an increase or decrease in the actual importance level of any particular component compared to that estimated by the PRA (which assumed that the outages are random) depends on the licensee's sensitivity to avoiding concurrent outages of pieces of equipment that would substantially increase the accident frequency. If actual maintenance practices are different from those modeled in the PRA, this information must be presented to the panel along with an assessment of the potential impact of these differences on the relative risk importance rankings derived from the PRA.

<u>Specific Guidance</u>

This inspection should be performance-based to the extent possible. The following is a suggested method for performing the inspection. If the licensee has elected to use methodologies that outside of NUMARC 93-01, then the inspector should consult with a regional or headquarters PRA specialist before proceeding with the applicable portion of this specific guidance.

<u>Inspection Objective 1</u>. Determine if a licensee has adequately established the safety significance of structures, systems, and components (SSCs) covered by the rule.

I. Preliminary Assessment

   A. Select a sample of SSCs covered by the rule that the licensee's expert panel has categorized as low-safety significant (LSS).

      1. The inspector should focus on those SSCs that the licensee determined were just below the selection criteria threshold for the high safety significant designation.

      2. The sample should include SSCs that are not explicitly modeled in the licensee's PRA.

      3. The sample should also include SSCs which have been removed from the list of high safety significant SSCs (as determined by NUMARC 93-01 numerical decision criteria) as a result of the decisions made by the expert panel.

   B. Review the licensee's basis for their categorization that these SSCs were low-risk significant and verify that the licensee has properly categorized these SSCs as LSS.

1. Probabilistic Considerations

   a. Do the SSCs meet the numerical decision criteria (CDF, RRW, and RAW) specified NUMARC 93-01?

   b. Did the licensee adequately assess the safety significance of SSCs outside the scope of their PRA?

   c. Is the level of detail of the PRA adequate to support LSS determinations?

   d. Does the quality of the PRA support the LSS determinations?

      1) Is the SSC correctly modeled in the PRA?

      2) Are the assumptions used in the PRA regarding the SSC valid?

      3) Did the licensee's risk ranking process include a consideration of the effects of periodic/systemic maintenance evolutions? (i.e. "rolling maintenance" schedules) If not, how have these issues been addressed?

   e. Are the licensee's PRA truncation limits low enough to support the LSS determination

2. Deterministic Considerations

   a. Do the LSS determinations account for design basis information and licensing commitments

   b. Do the LSS determinations account for the SSCs' importance in supporting operator actions needed to safety operate the facility or to mitigate an event?

   c. Does an LSS SSC have multiple applications in the plant and is susceptible to generic or common-mode failure that could affect redundant trains or multiple plant systems?

   d. Do the LSS determinations account for SSCs' functions in maintaining containment integrity and/or containment isolation?

   e. Do the LSS determinations account for SSCs' safety functions during low power operation, shutdown, refueling, and transitional modes of operation?.

f. Do the LSS determinations account for SSCs' safety functions during external events such as fires, earthquakes and high winds.

g. Has an SSC been improperly screened as LSS due to redundant LSS systems that perform the same safety function and therefore masked the significance of the SSC.

C. If the inspector identifies problems regarding the licensee's categorization of SSCs as LSS, then the inspector should expand the sample size to better assess the extent of the problems. If the inspector did not identify any problems and, time permitting, the inspector should also consider expanding the size of the inspection sample.

II. Problem Assessment

A. If the inspector identified problems with the licensee's safety significance determinations then the inspector shall assess the licensee's process(es) for making these determinations.

1. Procedural Controls

a. Was the level of guidance in Maintenance Rule procedures adequate?

b. Did the licensee follow the requirements of their Maintenance Rule procedures?

2. Performance of the Expert Panel

a. Were the expert panel's composition, its responsibilities, and its methods adequately defined?

b. Did the panel use clear criteria in classifying SSCs within safety significance categories?

c. Did the panel have adequate guidance to address the technical or analytical limitations of the plant specific PRA.

d. Did the panel consistently give SSCs of similar safety significance similar quality treatment?

e. Did the panel objectively consider deterministic and PRA information?

f. Did the panel incorporate lessons learned from its activities or the experiences of implementing line organizations?

g. Were expert panel activities documented so that the bases for important decisions and SSC classifications are recorded?

III. Final Assessment

A. No Significant Problems

1. If the inspector did not identify any noteworthy problems with the licensee's categorization of LSS SSC's, then the inspector can concluded that, based on the inspection sample, the licensee has adequately established the safety significance of SSCs as part of their Maintenance Rule implementation process.

B. Problems Identified

1. If the inspector identified noteworthy problems with the with the licensee's categorization of LSS SSC's, then the inspector needs to perform the following:

a. Determine if the problems are the result of programmatic weaknesses or failure to properly implement the program (i.e. failure to follow Maintenance Rule procedures).

b. Assess the safety impact of the problems.

c. Determine if the problems represented potential violations. See Inspection Procedure 62706 for detailed guidance.

Inspection Objective 2. Determine if a licensee has adequately set performance goals and criteria under (a)(1) and (a)(2) of the rule consistent with the assumptions used to establish the safety significance.

I. Preliminary Assessment

A. Select a sample SSCs covered by the rule and modeled in the PRA.

1. The sample should include both LSS and high safety significant (HSS) SSCs.

2. The sample should include SSCs that the licensee has categorized as inherently reliable.

3. The sample should include SSCs that the licensee has elected to run to failure.

B. If the licensee has established SSC performance criteria and set SSC performance goals using their PRA, then verify that the reliability and availability assumptions used in the plant specific PRA are not invalidated.

C. Review the sample of SSCs that have been determined to be inherently reliable, and verify that the SSC's condition or performance is acceptable without maintenance.

D. Evaluate the sample of SSCs that the licensee has elected to run to failure and verify that the licensee has followed their own methodology for determining safety significance. Review the licensee's PRA results to assess the safety significance of the SSC.

E. If problems are identified, then expand the sample size to better assess the extent of the problems. If no problems were identified and, time permitting, the inspector should also consider expanding the size of the inspection sample.

II. Problem Assessment

A. If the licensee has used less stringent values for reliability and availability then assumed in the plant specific PRA, then the results of the risk ranking procedure to determine safety significance may be invalidated. Question the licensee to determine the affect on the risk ranking process when the less stringent values for reliability and availability are modeled into the plant specific PRA.

B. If the material condition of an inherently reliable SSC is inadequate or the inherently reliable SSC's material history indicates that it is unreliable, then review the licensee's methodology for determining that an SSC is inherently reliable. If the licensee's methodology is unreasonable, then determine the extent of the problem.

C. If an SSC that the licensee has elected to run to failure is safety significant, then review the licensee's methodology for determining that the SSC provided little or no contribution to system safety function. If the licensee's methodology is unreasonable, then determine the extent of the problem.

III. Final Assessment

A. No Significant Problems

1. If the inspector did not identify any noteworthy problems with the licensee's establishment of SSC performance criteria and SSC performance goals, of the licensee then the inspector can concluded that, based on the inspection sample, the licensee has adequately set performance goals and criteria under (a)(1) and (a)(2) of the rule consistent with the assumptions used to establish the safety significance.

B. Problems Identified

1. If the inspector identified noteworthy problems with the with the licensee's establishment of SSC performance criteria and SSC performance goals, then the inspector needs to perform the following:

   a. Determine if the problems are the result of programmatic weaknesses or failure to properly implement the program (i.e. failure to follow Maintenance Rule procedures).

   b. Assess the safety impact of the problems.

   c. Determine if the problems represented potential violations. See Inspection Procedure 62706 for detailed guidance.

<u>Inspection Objective 3</u>. Determine if a licensee is using a rational approach to balance SSC unavailability for monitoring or preventive maintenance activities with the intended improvement in SSC reliability.

I. Preliminary Assessment

A. Obtain the following information from the licensee:

1. The criteria used to measure SSC reliability.

2. Availability data for HSS SSCs that have been unavailable (over the past 24 months) for periods of time that were significantly greater than assumed in the plant specific PRA. The time period of interest is the past two years.

3. Reliability data for HSS SSCs that have been significantly less reliable over the past 24 months than assumed in the plant specific PRA.

4. Select a sample of HSS SSCs that the licensee determined that reliability and unavailability have been successfully balanced.

B. Review the criteria used to measure reliability. Compare the this criteria with how the licensee models reliability in the PRA. If the reliability criteria is significantly different that used in the PRA, determine if the criteria is reasonable. If the licensee does not have criteria for measuring reliability, then question the licensee on how they are balancing reliability with unavailability.

C. Review the availability data and determine if licensee actions to improve SSC availability have been successful without a significant decline in SSC reliability.

D. Review the reliability data and determine if licensee actions to improve SSC reliability have been successful without a significant decline in SSC availability.

E. Review the licensee's underlying analytical basis for their determination that the reliability and unavailability of sample of HSS SSCs were balanced.

II. Problem Assessment

A. If the licensee's criteria to measure reliability does not exist or is not reasonable, then go to step III.B.1 below.

B. Availability

1. If there has not been notable improvement in an SSC's availability, then review and assess the actions the licensee had taken to improve availability.

2. Request the licensee to evaluate the change in risk associated of any significant decline in SSC reliability resulting from the licensee's efforts to improve availability.

C. Reliability

1. If there has not been notable improvement in an SSC's reliability, then review and assess the actions the licensee had taken to improve reliability.

2. Request the licensee to evaluate the change in risk associated with any significant decline in SSC availability resulting from the licensee's effort to improve SSC reliability.

D. If the underlying analysis that the licensee used for determining that HSS SSCs were successfully balanced is flawed, then question the licensee regarding their basis for determining that balance had been achieved. If the licensee's basis is not rational, then go to step III.B.3 below.

III. Final Assessment

A. No Significant Problems

1. If the inspector did not identify any noteworthy problems with the licensee's efforts to balance reliability and unavailability then the inspector can concluded that the licensee used a rational approach to balance SSC unavailability for monitoring or preventive maintenance activities with the intended improvement in SSC reliability.

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B. Problems Identified

1. If the licensee's criteria to measure reliability does not exist or is not reasonable, then the licensee cannot successfully balance reliability and unavailability. The licensee's maintenance rule program guidance is inadequate.

2. If the licensee has not been able to adequately balance SSC reliability and unavailability, then determine if the problems are the result of programmatic weaknesses or failure to properly implement the program (i.e. failure to follow Maintenance Rule procedures).

3. If the licensee does not have a rational basis for balancing reliability and unavailability, then determine if the problems are the result of programmatic weaknesses or failure to properly implement the program (i.e. failure to follow Maintenance Rule procedures).

4. Assess the safety impact of the problems.

5. Determine if the problems represented potential violations. See Inspection Procedure 62706 for detailed guidance.

Inspection Objective 4. Determine if the licensee has adequately assessed the overall effect on the performance of safety functions when SSCs are removed from service for monitoring or preventive maintenance.

I. Preliminary Assessment

A. Obtain plant operating/maintenance records for a several month period.

1. Select two or three periods of high maintenance activities during power operation with particular focus on periods where trains of components were removed from service or where components from different trains are out of service simultaneously for monitoring or preventive maintenance.

2. Select two or three periods of outage monitoring or preventive maintenance activities with particular focus on periods of reduced reactor coolant system inventory, reduced shutdown cooling availability or reduced electric power availability.

3. Obtain the licensee's safety assessment of those selected maintenance periods

B. Verify the licensee safety assessment encompassed all the SSCs (within the scope of the rule) that were out of service and or proposed to be removed from service for monitoring or preventive maintenance. Verify that the licensee has process controls in place that ensure safety assessments are performed prior to removing SSCs from service for monitoring and preventive maintenance activities.

C. Review the licensee's safety assessments of the selected maintenance periods. Determine if the licensee adequately evaluated the risks resulting from the monitoring or preventive maintenance activities.

1. In evaluating the licensee's assessment of maintenance activities, the inspector should ensure that the licensee has included a consideration of the following risk factors:

   a. The likelihood that a given maintenance activity will increase the frequency of an initiating event.

   b. The probability that the activity will affect the ability to mitigate the initiating event.

   c. The probability that the activity will affect the ability to use the containment as a measure of defense in depth.

2. Additionally, the licensee's assessments should include considerations which address the following factors:

   a. Whether multiple trains are affected by the maintenance activity.

   b. Whether the assessment is based on probabilistic insights.

   c. Does the assessment adequately address component and system dependencies?

   d. What assurances are made to prevent the concurrent unavailability of important combinations of equipment necessary for accident mitigation?

   e. What methods are employed to determine the duration of the maintenance and whether the projected duration is accounted for in the assessment?

3. In the event that the licensee chooses to use an approach such as a matrix of pre-defined allowable configurations, the inspector should ensure the following:

   a. What is the analytical basis for the allowed configurations? (i.e. is the matrix based on quantitative or qualitative considerations?)

   b. What provisions exist for accommodating configurations which may arise which are not encompassed by the matrix? The licensee should have a well documented process which specifies the procedures to be used in assessing the acceptability of such a configuration. Additionally, provisions should be made for exiting plant configurations which are either unacceptable or which cannot be adequately assessed.

4. In the event that the licensee chooses to quantify the proposed maintenance configurations using a "risk monitor," the inspector should ensure the following:

   a. The underlying analysis should be sound with respect to the technical attributes of the "risk monitor" model related to <u>scope</u>, <u>level of detail</u>, and <u>quality</u>.

   b. Did the "risk monitor" model accurately reflect the actual maintenance configuration?

   c. Did the licensee adequately validate the adequacy of the "risk monitor" model?

D. If problems are encountered while assessing the licensee's evaluation of risk due to maintenance, then the inspectors should contact a regional or headquarters PRA specialist for assistance and where a more detailed risk profile could be performed.

II. Problem Assessment

A. If the inspector identified problems with the licensee's plant configuration risk management then the inspector shall assess the licensee's process(es) for managing risk for maintenance activities.

1. Determine if the licensee has procedural requirements for evaluating affect of maintenance on plant risk. Determine if the guidance is adequate and is being followed.

2. If the licensee is relying on a "risk monitor" to manage risk, determine the extent of the weaknesses in the "risk monitor" model.

3. If the licensee has elected to manage risk by the development of risk windows (rolling maintenance schedule), determine if the licensee has appropriately utilized PRA insights in their development of these windows.

III. Final Assessment

A. No Significant Problems

1. If the inspector did not identify any noteworthy problems with the licensee's management of plant configuration risk resulting from maintenance activities, then the inspector

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can concluded that, based on the inspection sample, the licensee has adequately plant risk associate with maintenance activities.

B. Problems Identified

1. If the inspector identified noteworthy problems with the with the licensee's management of plant configuration risk, then the inspector needs to perform the following:

   a. Determine if the problems are the result of programmatic weaknesses or failure to properly implement the program (i.e. failure to follow procedures).

   b. The inspector shall also assess the effect on plant safety resulting from this weakness.

   c. Determine if the problems represented potential violations. See Inspection Procedure 62706 for detailed guidance.

TAB S

MAINTENANCE RULE NRR ~~OBSERVER~~ STAFF SUPPORT CONDUCT

TAB S
MAINTENANCE RULE NRR OBSERVER CONDUCT

The NRC Maintenance Rule Baseline Inspection Team has several NRR observers. It is essential that each of these observers are cognizant of the inspection plan, their objective and adhere to the following guidance to ensure the observer's actions are appropriate and they present a professional image without causing additional impact to the licensee.

MISSION/PURPOSE: The NRR observer will function only as an aide to the assigned individual inspectors. The observer is not an inspector. The observer will take directions from the team leader and assigned team inspector. The observer will monitor activities associated with the ongoing inspection to develop future improvements to this inspection process and to help ensure uniformity. The observer will help the inspector develop the individual inspection plan and ensure that each plan is completed within the allocated time. The observer helps the inspector develop questions for interviews and shadows the assigned inspector during tours, visits, and interviews. The observer is only an OBSERVER and is assigned the mission to develop improvements to the inspection plan, helps ensure uniformity, and develops recommended improvements through a written after action report. The observer SHALL NOT interfere with the inspection, shall not be asking technical questions of the licensee, interrupting the inspector, talking during an interview, or making informal or official request of the licensee. All recommendations and request should come through the inspectors and team leader. The observer should remain silent during interviews and take notes to be included within the after action report. During the team meeting each day, after the inspector has briefed the team leader on the daily findings, the observer will provide an on-the-spot recommended adjustments for the following days activities and record these recommendations into the observer's after action report notebook with a copy to the team leader. The final after action report will be developed during the documentation phase of the inspection and submitted to the team leader with recommended improvements. If question arise during the inspection that need clarification, the observer should contact the Team Leader or Assistant Team Leader for directions.

Draft Rpts from
Computer Disk

INSPECTOR'S INPUT

INPUT FOR ST LUCIE INSPECTION REPORT No. 50-335,338/96-04

DATES OF INSPECTION: MARCH 25-29, 1996

A. Inspector Concurrence: ______________________________
J. L. Coley, Jr. Reactor Inspector

Branch Chief Concurrence: ______________________________
D. M. Verrelli, Acting Branch Chief
Special Inspection Branch

B. 1.0 Persons Contacted

*R. Ball, Supervisor, Maintenance
*E. Benken, Licensing
*D. English, Supervisor, Maintenance
*H. Jacobs, Supervisor, Maintenance
*G. Madden, Acting Licensing Manager
*A. Menocal, Supervisor, Maintenance Programs and Planning
*L. Motley, Supervisor, Maintenance
*J. Scarola, Plant General Manager
*S. Valdes, Information Services

Other licensee employees contacted during this inspection included craftsmen, technician, and engineers.

C. Input for appropriate inspection area.

3.0 Maintenance - (62703)

3.1 Observation of In-process Corrective Maintenance Activities - Units 1 and 2

Portions of the mechanical maintenance for the equipment listed below were observed by the inspectors to verify that corrective maintenance activities for systems and components are conducted in a manner which results in reliable safe operation of the plant and plant equipment. Specific elements verified during this assessment included the following: applicable tools were properly calibrated; correct parts and tools were used; personnel were qualified and knowledgeable; supervision and QC (where applicable) were adequate; proper approvals were obtained before work began; safety and radiation controls were in place; and approved procedures/instructions were followed. Procedures used to control this work consisted of the following: ADM-08.02 Revision 8, "Conduct of Maintenance", GMP-05, Revision 3, "Control of Welding Special Processes", STD-W-012, Revision 1, "Examination Requirements for Welds", General Maintenance Procedure No. M-0043, Revision 15, and General Maintenance Procedure No. 2-M-0041, Revision 29.

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- Replacement of Valve No. V23113 on Unit 2 was observed. This is the 4 inch isolation valve for the Steam Generator Closed Blowdown to the Heat Exchanger 2A-1 Inlet. Work was conducted in accordance with Master Work Order Task No. 95-028027-1A. The inspector observed welding preparations and fitup. In addition, the inspectors verified that work was performed in accordance with written instructions, proper revisions of procedures were used, welder certification, welding procedure parameters and weld filler material controls and certifications were satisfactory.

- Welding activities for ACC-3B were observed. This is the Unit 1 air cooled condensing unit for the control room ventilation system. Work was conducted in accordance with Work Order Task No. 96-0065401. Welder certification, welding procedure parameters, and weld filler material controls and certifications were verified satisfactory.

- Liquid penetrant examination activities were observed for a new pipe/valve assembly on the Unit 2 Steam Generator Closed Blowdown system. Work was conducted in accordance with Work Order Task No. 96003894 and Traveler Nos. 96-373, 4, 5, and 6. Examination of welds No. 2001, 2002, 2003 and 2004 for valves No. V23139 and V23140 were observed. The inspector verified that the examinations were conducted in accordance with approved procedure No. PT-1, Method 1, Technique sheet 9.5, Rev. 5. Welding filler materials, welder certification and welding procedure parameters were also verified.

- Portions of maintenance activities involving the replacement of packing for Unit 2 Charging Pump No. PP2B were observed. This work was performed in accordance with Master Work Order Task No. 96006925-01 and General Maintenance Procedure No. 2-M-0041, Revision 29. The inspectors verified that work was conducted in accordance with the approved procedure, craftsmen were knowledgeable of the work process, and the proper revision of the work procedure had been verified.

- Corrective maintenance for Unit 2 Steam Generator Closed Blowdown system Valve No. V23139B was observed. This is a 3/4 inch root valve for the 2B1 heat exchanger which had developed a steam leak in the valve's bonnet to body connection. Master Work Order Task No. 96003894-01 and General Maintenance Procedure No. M-0043 was used to performed this maintenance activity. However, corrective maintenance was ineffective due to valve's state of deterioration. A determination was subsequently made to replace the valve.

- Portions of the tube cleaning activities in the 1A2 Inlet waterbox on the Unit 1 Condenser (1A) was observed. This work was conducted in accordance with Master Work Order Task No. 9600612101.

During the above work activities the inspectors noted that the craftsmen would go verify that the procedure they were using was the appropriate revision in accordance with the requirements of paragraph 4.5 in Procedure No. QI6-PR/PSL-1 (Document Control). One occasion when the inspectors accompanied the craftsmen to perform this verification the craftsmen found that Revision 14 of Procedure No. M-0043 which the planner had furnished in the maintenance package was not the current revision when compared with the maintenance control copy in the North Service Building. Further review by the inspectors also revealed that the procedures index was not being updated when new procedure revisions were received as the cover sheet of the index stated. The inspectors also questioned whether the control procedures were available to backshifts since the doors of the room had locks on them.

Discussions held with appropriate management personnel regarding the above procedure control concerns. The discussion revealed that document control only considered the procedure index correct on the date indicated on the index cover sheet. In accordance with procedure this is a dated once every three months when control copies of the procedures are audited against an up to date index. The inspector was also informed that the craft know to verify their procedures against the control copies of the documents verses the index. Since the index is a memorandum and by procedure does not supersede the requirements of a control document. Based on observations of craftsmen audited this inspection, procedures in the maintenance package are verified against the control copy of the procedure. In addition, the craftsmen audited followed the document control procedure and used the correct revision of the procedure in each case. The apparent discrepancy of the planner issuing the incorrect revision of General Maintenance Procedure No. M-0043 resulted because the planner had entries to made in the procedure and on the date he made these entries he had verified revision as the correct revision on that date. This therefore, was not a discrepancy but one of the reason the craftsmen are required to verify the procedure before use.

As a result of above findings and questions raised by the inspector, two STAR Action Reports were written (Nos. 960456 & 7) to evaluated the effectiveness of document control. Management's attention focused on corrective actions in response to these reports and during the week the inspector was on site (March 25-29, 1996, the following corrective measures were established.

- All maintenance groups now will use only one new centralized library in the North Service Building. This library has an attendant manning it and updating control procedures 10 Hrs. a day. The room where the library is located has also had the locks removed from the doors in order that no backshift personnel are excluded from using the facility.

- The document index cover sheet has been revised to insure that this uncontrolled document is not used for procedure status except on the date indicated on the cover sheet.

- When planners now verify procedure revisions during the planning stage they will double stamp the procedure and only sign one verification blocks. This will require the user to also verify the procedure.

- An up to date procedure index will be established on all on-line computers by approximately August 1996. When this enhancement is fully implemented the index will supersede all documents for establishing procedure status. All plant personnel will have access to the index at that time.

The inspectors considered the steps taken or in the process of being taken by the licensee to be substantial improvements in document control. All actions observed during the above corrective maintenance were also found to be satisfactory.

D. 7.0 Exit Meeting

The inspection scope and results were summarized on March 29, 1996, during a pre-exit meeting with the licensee. The inspectors described the areas inspected and discussed in detail the inspection results. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

E. 8.0 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with the UFSAR commitments. During an approximate two month time period all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and/or parameters.

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

F. 9.0 Summary Statement

Plant corrective maintenance was conducted in accordance with the applicable approved instructions by knowledgeable craftsmen. Corrective actions taken by the licensee to improve the control of documents were considered appropriate for the situation.

H. IFS Forms - Attached to hard copy

I. Completed NOV - None File S:\DRS\SIB\STL9604.JC

INSPECTION PLAN

INSPECTION OF: ST Lucie 1 & 2

INSPECTION DATES: May 6-9 St. Lucie. May 10th EPRI and May 13-17, 1996

REPORT NUMBERS: 50-335.328/96-06 For inspection performed on May 6-9
50-335.328/96- To Be Announced May 13-17, 1996

TYPE OF INSPECTION: Core (Maintenance and Surveillance) May 6-9, 1996
May 10, 1996 EPRI Review of Southwest Research Institute Qualification Data for St Lucie Reactor Vessel Inspection
May 13-17, 1996 Core (Inservice Inspection of Reactor vessel.

INSPECTOR: J. L. Coley

INSPECTION OBJECTIVES: To evaluate the effectiveness of the licensee's maintenance and surveillance activities and to examine Automated Ultrasonic Examination of Reactor Vessel plus other ISI activities.

INSPECTION REQUIREMENTS: Preplaning review of maintenance documents, TS, FSARs, PPR, SALP Reports, and Plant Status Report for this inspection will be performed May 2-3, 1996.

ANALYSIS OF SITE MATRIX: Matrix will be reviewed before inspection is performed as part of the preplaning review detailed above.

IPE IMPORTANT SYSTEMS: High Pressure Safety Injection, Emergency Power Systems, and Component Cooling Water

Senior Resident Perspective: The senior resident inspector stated that he would like me to focus on the visual Reactor Vessel internals examination, Steam Generator eddy current examinations, and the Reactor Vessel 10-Year automated ultrasonic examinations

Outstanding Items: Unresolved Item No. 335/94-008-03, Quality Level of PORV and SRV Discharge Piping

Lodging During Inspection: Holiday Inn @ Jensen Beach 407-225-3000
Lodging At EPRI : Hampton Inn, Charlotte (Unversity Place) 704-548-0905

In Charge of Exit Interview: Senior Resident Inspector (End of Month) Briefing with management at end of this inspection - J. L. Coley

Branch Chief's Instructions: None to date

Approving Branch Chief: D. Verrelli ______________________

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Date Submitted to Branch Chief: 4-17-96

Date Projects Informed: 4-17-96

Date Plan Provided to Projects: 4-17-96

Copies Provided:

Maintenance Branch Chief: Chris Christensen, 4-17-96

Project Branch Chief: K. Landis, 4-17-96

Project Engineer: E. Lea, 4-17-96

Original to Branch Files: Special Inspection Branch

INSPECTOR'S INPUT

St. Lucie 96-06

A. Inspector Concurrence:________________________
J. L. Coley, Jr. Reactor Inspector

Branch Chief Concurrence:________________________
P. E. Fredrickson, Branch Chief
Special Inspection Branch

B. 1.0 Persons Contacted

G. Boyers, Level III, Eddy Current Examination Examiner
F. Carr, Section Supervisor, Nondestructive Examination (NDE)
J. Connor, NDE Supervisor
C. Ward, Mechanical Engineer

Electrical Power Research Institute (EPRI)

P. Ashwin, Project Manager, RPV Performance Demonstration
L. Becker, Performance Demonstration Administrator
T. Kimball, NDE, Specialist

Licensee employees contacted during this inspection included maintenance technicians, nondestructive examination technicians, and engineering personnel.

C. Input for appropriate inspection area.

3.0 Maintenance Implementation

3.1 Observation of In-process Corrective Maintenance Activities (62703) Unit 1

The inspector observed maintenance activities on the components listed below to determine if the activities were conducted in accordance with regulatory requirements, technical specifications (TS), approved procedures, and appropriate industry codes and standards.

3.1.1 Master Work Order: 95-02643-01C, Jack and Lap New Pressurizer Safety Valves

Due to seat leakage problems experienced with the previous design pressurizer safety valves, Florida Power and Light (FP&L) elected to replace these valves with a new forge body design which accommodated a flexi-disc seat enhancement. During site verification nitrogen seat set pressure and bubble tests conducted in accordance with Master Work Order No. 95-026432-01B, Crosby's Technical Manual No. 8770-5460 Revision 10, and Maintenance Procedure No. M0017 Revision 33, two of the new valves, Serial Nos. N84217-00-0002 and N84217-00-0004 failed to pass the seat leak test. As a result, the valve bonnets with the valve internals for the two valves that failed were required to be disassembled from the valve body so the valve seats could be lapped. From May 6-8, 1996, the inspector observed the "Jack and Lap" activities conducted in accordance with MWO 95-02643-01C by a Crosby Valve and Gage Company representative, FP&L Maintenance personnel and site engineering. The inspector also observed that the retest of both valves was conducted in accordance with MWO 95-026432-01B and Maintenance Procedure M0017. The valve retests were satisfactory and all work activities observed were conducted in accordance with the approved written instructions by knowledgeable personnel.

3.1.2 MWO-95028905-01, Clean Component Cooling Water Heat Exchanger

On May 8, 1996, the inspector observed maintenance personnel performing heat exchanger tube hydrolazing operations on Component Cooling Water Heat Exchanger 1A in accordance with MWO 95-028905-01. During review of the work package for this cleaning and repair activity the inspector noted that the information copies of the control procedures had not been verified as the correct revision with the control document, initialed, and dated as required by Document Control Procedure No. QI 6-PR/PSL-1. The procedures involved were MMP-14.1 Revision 6, Component Cooling Water Heat Exchanger Cleaning and Repair", GMP-02 Revision 13, "Use of M&TE By Mechanical Maintenance", and Maintenance Procedure M-0064 Revision 1". The inspector subsequently verified that the procedures in question were in fact, the correct revision. However, upon being notified, FP&L maintenance supervision personnel stopped all work on the Component Cooling Water Heat Exchanger until the cause of this discrepancy could be determined. Corrective actions included replacing the lead maintenance technician on this job and conducting briefings with maintenance personnel on all shifts to insure that outage maintenance personnel knew they were personally responsible for insuring work was conducted in accordance with current revision of procedures and that, procedures are stamped, signed, and dated as required. This failure constitutes a violation of minor significance and is being treated as a Non-cited Violation (NCV) consistent with Section IV of the NRC Enforcement Policy. The NCV was identified as NCV No. 50-335/96-06-01, "Failure to Document Verification of Current Procedure Revisions".

3.1.3 Inservice Inspection (ISI) Unit 1

The inspector reviewed documents and records, and observed activities as delineated below to determine whether ISI activities were conducted in accordance with applicable procedures, regulatory requirements, and licensee commitments. The inspector's objective was to examine the licensee's steam generator examination and evaluation activities and the 10-year ultrasonic examination of the reactor vessel. The applicable code for this ISI is the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, 1983 Edition with Summer 1983 Addenda. St Lucie Unit 1 is presently in the first outage of the third 40 month period, of the second 10-year ISI interval. This is the thirteenth refueling cycle for Unit 1.

Eddy current acquisition activities were conducted by ASEA, Brown & Boveria INC (ABB)/Combustion Engineering. Primary analysis of eddy current data was conducted by Zetec in Issaquah, Washington and the secondary analysis was conducted by ABB at the Florida Power and Light NDE Laboratory in West Palm Beach, Florida. The Unit 1, 10-year Reactor Vessel examinations were conducted by Southwest Research Institute.

3.1.3.1 Review of Procedures, Guidelines, and Licensee Documents (73052)

The following documents were reviewed by the inspector during the assessment of ISI activities.

- FP&L Eddy Current Examination Procedure No. NDE 1.3 Rev. 8, Entitled: Eddy Current Examinations of Non Ferromagnetic Tubing Using Multi-Frequency Techniques MIZ-18/MIZ-30

- FP&L Document No. CSI-ET-96-11 Rev. A, Unit 1 Steam Generator Eddy Current Examination Plan

- FP&L Letter of Response to Generic Letter 95-03, Dated June 23, 1995

- FP&L Safety Evaluation No. JPN-PSL-SEMP-95-112, Rev.1, Entitled: Cracking of Westinghouse Alloy 600 Mechanical Steam Generator Tube Plugs

- PC/M 125-195M, Rev. 1, Entitled: Steam Generator Tube Plugging and Plug Repair

- St. Lucie Unit 1 Eddy Current Data Analysis Guideline and Performance Demonstration, Dated May 1996

- Southwest Research Institute (SwRI) Procedure No. SLC-AUT-14 Rev. 1, Change 1, Entitled: Automated Ultrasonic Inside Surface Examination of Pressure Piping Welds

- SwRI Procedure No. SwRI-AUT2 Rev.9 Change 1. Entitled: Automated Ultrasonic Inside Surface Examination Indication Resolution and Sizing

- SwRI Procedure No. SLC-AUT15 Rev. 2. Change 1. Entitled: Automated Ultrasonic Inside Surface Examination of Ferritic Vessels Greater Than 4.0 Inches in Thickness

- FP&L Document No. PSL-100-AOA-95-1 Rev.0. Dated April 5. 1995. Entitled: Request For Authorization of Alternative Examination

- NRC Safety Evaluation of FP&L's Request for Authorization of Alternative Reactor Pressure Vessel Examinations For St. Lucie Plant. Unit 1

- SwRI Procedure No. SLC-PDI-AUT1 Rev.0. Change 1. Entitled: Automated Ultrasonic Inside Surface Examination of Ferritic Vessel Wall Greater Than 4.0 Inches in Thickness

- SwRI Procedure No. SLC-PDI-AUT2 Rev. 0. Change 1. Entitled: Automated Inside Surface Ultrasonic Flaw Evaluation and Sizing

The inspector's review of the above documents revealed they were in accordance with the applicable ASME Code. Technical Specifications. licensee commitments. and industry guidelines. In addition. the inspected noted that. the licensee's augmented eddy current examination plan. plug-a-plug tube plugging activities and alternative reactor pressure vessel examinations revealed good outage planning had been performed and component safety should be enhanced. based on these defensive barriers.

3.1.3.2 Observation of Steam Generator Eddy Current Acquisition and Steam Generator Plug-A-Plug Repair Activities (73753) Unit 1

From May 6th until May 9th. 1996 the inspector observed portions of the licensee eddy current data acquisition and the Westinghouse tube plug cleaning activities. These activities were conducted in accordance with the approved procedures delineated above and the FP&L Examination Plan.

3.1.3.3 Review of SwRI Ultrasonic Examiner Performance Demonstration Records at the Electric Power Research (EPRI) In Charlotte N.C.

On May 10. 1996. the inspector and a representative from FP&L visited the EPRI NDE Center to review the performance demonstration examination results for the four SwRI data analyst that would be used by FP&L to examine the Unit 1 reactor vessel. This review was necessary because FP&L's

relief request entitled. "Request for Authorization of Alternative Examination Methods" which was applicable for Unit 1 reactor pressure vessel welds which had limiting conditions that prevented 100 percent examination coverage had two alternative examinations proposed by the license that had changed since NRC had approved the relief request.

The first change was that the licensee had initially stated that a full vee 45° shear wave examination would be performed to the extent practical to compensate for recorded limitations. However, the current SwRI examination procedures did not have this examination method in them. The second change to the April 1995 Relief Request stated that, FP&L would employ as they became available additional examinations, inspections and/or techniques that would provide a substantial increase in the examination of areas currently missed under the current examination techniques.

To comply with their commitment to employ examination techniques that provide a substantial increase in the examination of weld areas currently missed, FP&L had SwRI qualify to the performance demonstration examinations conducted by the EPRI NDE Center for a single side weld access examination. These examinations are conducted in accordance with Appendix VIII of later editions of the ASME Code. The editions of the Code which include Appendix VIII have not been approved for use by NRC at this time. The applicable ASME Section XI Code presently requires that a weld be examined from two directions (both sides of a weld). Therefore, to supplement the Unit 1 Reactor Vessel examinations with these new alternative techniques the licensee invoked paragraph IWA-2240 of the applicable ASME Code which states that, "alternative examination methods, or newly developed techniques may be substituted for the methods specified provided the inspector (the Authorized Nuclear Inspector [ANI]) is satisfied that the results are demonstrated to be equivalent or superior to those of the specified method".

Although the ANI had approved the single side weld examination techniques the inspector had the following questions concerning the single side weld access test parameters and the examiner's performance.

- How many of the defects were in the test blocks were on the far side of the weld?

- Was the depth location of the defects represented on both sides of the weld?

- How many of the far side weld defects were notches verses cracks?

- What was the effective focal length of the SwRI Duplex Send and Receive transducers?

- How effective had the SwRI examiners been during their qualification effort on the far side weld indications?

- Could an examiner pass the test and miss one or more far side weld indications?

- Detection Criteria delineated in Paragraph 8.1.(2)(b) of SwRI Procedure No. SLC-PDI-AUT1 stated that, "if an indication cannot be confirmed with at least 2 channels, it will be considered irrelevant". SwRI one sided examinations will only have two channels active, representing two different examination angles. Since far sided weld indications should be oriented at a slightly different angle than near side weld indications because defects tend to follow the weld heat affected zone on both sides of the weld. Is it logical to presume that 100% detection capability will be achieved with both angle beam transducers on indications when weld location and defect orientation differ?

EPRI's Performance Demonstration Administrator reply to the inspector's first question was that there was no weld in the test blocks used for the single side access weld qualification test. EPRI's position was that the weld would not make a <u>significant</u> difference in the ability to detect or size indications in the carbon steel reactor vessel. The inspector however, was concern that the acoustical differences between the vessel base material and the weld, and the defect orientation differences had not been at least analytically defined and factored into the difficultly of the performance demonstration test. Therefore, the performance test may not be ultrasonically representative of the reactor vessel welds.

Discussions with EPRI personnel and review of documents and examiner test results satisfactorily resolved the questions listed above other than those that related to the failure of the test sample to include a weld.

The inspector returned to the St. Lucie facility on May 13, 1996 to continue his examination of inservice inspection activities. At that time the inspector will addressed this concern with the appropriate licensee management personnel and determined the licensee position on this matter. Continuation of the inspection will be reported in NRC Inspection Report No. 96-08.

7.0 Exit Meeting

The inspection scope and results were summarized on May 13, 1996, during a meeting with the licensee. The senior resident inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

(Open)/(Closed) Non-cited Violation 50-335/96-06-01, "Failure to Document Verification of Current Procedure Revisions", Paragraph No. 3.1.2.

E. 8.0 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with the UFSAR commitments. During an approximate two month time period all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and/or parameters.

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

F. 9.0 Acronyms

ABB	-	ASEA, Brown and Boveria
ASME	-	American Society of Mechanical Engineers
B&PV	-	Boiler and Pressure Vessel
EPRI	-	Electrical Power Research Institute
FP&L	-	Florida Power and Light
ISI	-	Inservice Inspection
M&TE	-	Mechanical & Test Equipment
MWO	-	Master Work Order
NCV	-	Non-Cited Violation
NDE	-	Nondestructive Examination
NRC	-	Nuclear Regulatory Commission
RPV	-	Reactor Pressure Vessel
SwRI	-	Southwest Research Institute
TS	-	Technical Specifications
UFSAR	-	Updated Final Safety Analysis Report

G. 10.0 Summary Statement

Maintenance activities which upgraded the Pressurizer Code Safety Valves with a new improved design valve, the licensee's augmented eddy current examination plan, plug-a-plug steam generator tube plugging activities which prevent tube plug leakage, and alternative reactor pressure vessel examinations revealed good outage planning had been performed and component safety should be enhanced, based on these defensive barriers. Work activities observed were conducted by well qualified and knowledgeable personnel. However, one non-cited violation was also addressed in this report whi dealt with improper control of work procedures.

INSPECTOR INPUT FOR ST LUCIE MAINTENANCE TEAM INSPECTION REPORT

INPUT FOR INSPECTION REPORT NO.: 50-335,389/96-13

INSPECTOR: James L. Coley, Jr.
Reactor Inspector, Special Inspection Branch
Division of Reactor Safety

DATES OF INSPECTION: September 16-20, 1996

Inspector: ______________________________
James L. Coley, Jr. Reactor Inspector   Date Signed

Approved By: ______________________________
D. M. Verrelli, Chief   Date Signed
Maintenance Branch
Division of Reactor Safety

I. OPERATIONS

04 Operator Knowledge and Performance

04.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection, the inspector interviewed one senior reactor operator (SRO) to determined if he understood the general requirements of the Maintenance Rule and his duties and responsibilities for its implementation. The inspector asked the SRO to explain the general requirements of the Maintenance Rule and to describe his responsibilities for implementing these requirements. The inspector also had the SRO to explain in detail the risk assessment matrix.

b. Observations and Findings

The tasks associated with the rule that operators were responsible for included:

- Determining the impact on availability of SSCs when tagging equipment out-of-service and performing administrative requirements for tagging.
- Determining SCCs out-of-service logging requirements and impact on availability.
- Evaluating priorities for system restoration.
- Evaluating job scheduling activities.
- Evaluating plant configuration to determine if work authorization created undue risk.

The operator understood the purpose of the rule and his required duties for

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Rule implementation, which included logging in- and out-of-service equipment within the scope of the Rule and assessing the risk of emergent work items in accordance with the plant configuration risk assessment matrix.

c. Conclusions

The senior reactor operator interviewed understood the purpose of the rule. and his assigned duties for implementing the rule.

II. MAINTENANCE

M1 Conduct of Maintenance

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 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 inspectors reviewed site procedure Nos. ADM-17.08, "Implementation of 10 CFR 50.66, The Maintenance Rule", ADM-17.03, "Operating Experience Feedback program" and SCEG-008, "Guidelines for Maintenance Rule Periodic Assessments" which implemented the licensee's commitments regarding periodic evaluations, held discussions with the Maintenance Rule Administrator who is responsible for preparing Maintenance Rule periodic assessments, reviewed the July 9,1996 quarterly report, and reviewed a draft copy of the licensee 1st periodic assessment for the emergency diesel generator (EDG) system.

b. Observations and Findings

On June 29, 1995, license amendments were issue to remove EDG accelerated testing and special reporting requirements from the ST. Lucie Technical Specifications. The amendments required the implementation of an EDG maintenance program that complies with the requirements of 10 CFR 50.65 and Regulatory Guide 1.160 within 90 days. As a result, a commitment date of September 29, 1995 was established for EDG Maintenance Rule implementation. Due to the early implementation of the Maintenance Rule for the EDGs, the requirements for the performance of a periodic assessment have become due for the EDGs. The remainder of the site Maintenance Rule program began implementation on July 10, 1996, in compliance with 10CFR 50.65 and will be due next year shortly after July 10, 1997. Both Units will be performed concurrently at this time.

The licensee's commitments regarding periodic evaluations of the Maintenance Rule activities are as follows:

- Maintenance Rule Quarterly Report - A report which documents the results of structures, systems, and components (SSCs) performance, SSCs considered for goal setting and monitoring per section (a)(1) of the rule, as well as SSC degradations, trends and pertinent industry wide operating experience.

- Periodic Assessment - A higher-level, comprehensive evaluation performed annually at mid-year following Maintenance Rule implementation dates.

The inspector reviewed the licensees quarterly report dated July 9, 1996 for all SSCs and a draft copy of the St. Lucie Maintenance Rule Periodic Assessment for the EDGs. The Emergency Diesel Generator system is currently not meeting established performance criteria and is in Maintenance Rule (a)(1) status for the following conditions:

- Unit 1&2 EDGs have experienced repetitive maintenance preventable functional failures with the governors.

- Unit 1 B EDG has exceeded its performance criteria for unavailability hours and has exceeded trigger values prescribed by the Emergency Diesel Generator Reliability Program.

The inspector confirmed that corrective actions were taken, industry-wide operating experience was reviewed, and goal setting and monitoring activities have been established by the licensee. The inspector also noted that preventive maintenance activities were adjusted as required by paragraph (a)(3) whenever a goal or performance criteria was exceeded or whenever a SSC experienced a maintenance preventible functional failure.

c. Conclusions

The licensee's procedures, draft periodic assessment for the EDGs, and quarterly report for all SSC's implemented the requirements of the Rule and were considered a maintenance program strength.

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

a. Inspection Scope (62706)

The inspector reviewed program documents and records in order to evaluate the process that had been established to set goals and monitor under paragraph (a)(1) of the Rule. The inspectors also discussed the program with the Maintenance Rule Administrator and system engineers.

The inspector reviewed the systems described below to verify: that goals or performance criteria were established with safety taken into consideration; that industry-wide operating experience was considered where practical; that appropriate monitoring and trending was being performed; and, that corrective action was taken when SSCs failed to meet goal or performance criteria, or when SSC experienced a maintenance preventible functional failure (MPFF).

b. Observations and Findings

The inspector reviewed selected systems containing SSCs that were considered as within the scope of the Maintenance Rule and were monitored under paragraph (a)(1) of the Rule. These systems included SSCs which have not met established performance criteria or were a leading contributors in exceeding plant level performance criteria for unavailability. Specifically the inspector verified that the licensee had implemented goal setting and monitoring as required by paragraph (a)(1) of the Rule for the Unit 1 'C'

Auxiliary Feedwater (AFW) Train and the Reactor Coolant Pump Seals.

- The Unit 1 'C'AFW train exceeded its performance criteria for reliability when it experienced three MPFFS in an 18 month period. The primary cause of the MPFFs was due to corrosion on electrical contact surfaces in the turbine pump governor coil and a motor operator valve (MOV)(SMB-000) torque switch. As corrective action the licensee upgraded the SMB-000 actuator and the Unit 1 EGR coil resistance PMs from a 18 months frequency to a 6 months frequency and required that as-found and as-left resistance checks be performed. The reliability criteria was also changed from ≤ 2MPFFs/train per 18 months to no SBM-000 actuator PMT contactor failures after new the PM is implemented for 18 months and no as found out of spec EGR resistance checks for 18 months. The inspector however, noted a problem with the goals established by the licensee in that, the system engineer had no basis for the acceptance criteria had been established for the resistance checks. The system engineer had elected to establish a starting point for monitoring resistance of one hundred OHMs resistance for the governor coil and adjust the acceptance criteria after monitoring the PM values for 18 months. This seem satisfactory to him because the as-found failed condition of the governor coil was one thousand OHMs. The torque switch resistance check start monitoring point was set at two hundred Mil-OHMs per instructions from a electrical engineer. The inspector noted however, that the value given for the governor coil resistance checks in the technical manual was 35 OHMs. The inspector considered the technical manual values should have been used when establishing preliminary acceptance criteria for taking resistance readings and additional points could be obtained by taking measurements on in-house spares and/or values established by industry using industry operating experience. The system engineer could still monitor deviations from this norm to align the criteria for the environmental conditions at the St. Lucie Plant. As a result of questioning the acceptance criteria, the system engineer contacted an electrical engineer who advised the system engineer to use resistance check criteria within 125% of the 35 OHMs recommended in the vendor technical manual. The system engineer informed the inspector that value would be used. However, the inspector considered the licensee's failure to use acceptance criteria recommended in the vendor technical manual when setting a goal to be a weakness in the licensee's maintenance program.

- The Unit 1 and Unit 2 Reactor Coolant Pump (RCP) Seals were a large contribution to exceeding the plant level unavailability criteria when 1A2 RCP seal failed in August 1995 and in April 1996, and the 2A2 RCP experienced a failure in September 1995. However, the RCP seals in themselves did not lead directly to the criteria being exceeded. The licensee's expert panel elected as a conservative entry to put the RCP seals into category (a)(1) in order to establish realistic goals and closely monitor the performance of a risk significant SSC. The inspector interviewed the system engineer for the reactor coolant system and noted with pleasure that this engineer keep an excellent notebook on his system. this notebook included trending data on each pump to determine appropriate RCP seal life. Other data requested during the interview was also found well documented in this notebook. The inspector attended a management training meeting on the RCP seals:

expert panel meeting minutes on the RCP seals were reviewed: as well as corrective action documents such as STAR 1-950988. Problem Report 95-017. Condition Report 96-598. and RCP 1A2 Seal Root Cause Analysis dtd August 25. 1993. The inspector also reviewed the corrective action taken by the licensee as well as the goals set to improve the performance of the RCP seals which included increasing the frequency for changing the RCP seals out to no more than two cycles. In addition next outage the licensee will install an enhanced (N9000 Series) seal in one RCP pump to verify its improve performance capabilities with the intention of going to this seal if upgraded performance can be established.

c. Conclusion

The licensee has considered safety in establishment of monitoring and goals for the above SSCs. However, failure of the licensee use vendor establish acceptance criteria for verifying acceptable contact point resistance in the governor coil for the turbine pump on the Unit 1 'C' AFW train was considered to be maintenance program weakness.

M1.7 Preventative Maintenance and Trending SCCs (a)(2)

a. Inspection Scope (62706)

The inspector reviewed licensee documentation and records in order to evaluate the process that had been established to set performance criteria and monitor under paragraph (a)(2). The inspector also attended a expert panel meeting on revisions to the scoping document for monitoring the effectiveness of maintenance on structures, discussed the program for the steam generators and structures with the Maintenance Rule Coordinator. and interviewed the system engineers for the SSCs examined.

The inspectors reviewed the systems and structures described below to verify: that performance criteria were established with safety taken into consideration: that industry-wide operating experience was considered where practical: that appropriate monitoring and trending was being performed: and that corrective actions were taken when SSCs failed to meet performance criteria, or when a SSC experienced a MPFF.

b. Observations and Findings

The inspector reviewed portions of selected systems containing SSCs that were considered as being within the scope of the Maintenance Rule, but were not monitored under paragraph (a)(1) of the rule. These systems included main steam and reactor coolant for the steam generators and select structures which specifically included the Unit 1 refueling tank and foundation, Unit 1 intake structure and retaining walls, and operations support building.

- Structures - Based on interviews with the cognizant engineer within the licensee's civil engineering organization and review of the following implementing procedures: ADM-17.08 (Implementation of 10 CFR 50.65, The Maintenance Rule), Scoping Document for the Implementation of the Maintenance Rule for Monitoring the Effectiveness of Maintenance on Structures (Revision 2), SCEG-003 Rev. 1 (Guideline for the Condition

Survey of Structures and Supports by Plant Personnel), and SCEG-009 Revision 0 (Guideline for Maintenance Rule Structural Condition Monitoring by a Qualified Inspector), the inspector concluded that the licensee had selected the correct structures to be monitored under the Maintenance Rule and had established a systematic program for monitoring the condition of these structures. The licensee has begun the initial baseline survey of structures which to date has consisted of the Unit 1 refueling water storage tank and the Unit 1 intake structure and retaining walls. All baseline inspections are to be completed by December 31, 1997. Periodic surveys will then be performed throughout the life of the plant on intervals not to exceed five years. The inspection attributes used in the walkdowns for baseline inspections and the periodic surveys of structures are based on applicable design criteria as implemented in the above procedures using surveillance check sheets. Significant discrepancies identified during walkdown down inspections are identified in condition reports and photographs are taken of the findings in order that comparisons can be made of discrepant conditions during subsequent inspections. The licensee uses knowledgeable and experienced civil engineers to perform the structural inspections. The inspector reviewed the results of the licensee's baseline inspection for the Unit 1 intake structure and discovered that the Condition Report for intake structure listed 15 different line items of discrepancies for this structure. Photographs of the discrepancies revealed cracks and segregations. However, the inspector also found that the licensee has no established performance criteria for moving a structure from the (a)(2) category and placing it in the (a)(1) category for additional monitoring and goal setting. The inspector questioned the civil engineer as to how bad of condition would the intake structure would have to be in before it would place into the (a)(1) category. The engineer stated that, although there was no criteria he would probably place this structure in (a)(1) the next interval inspection if degradation continues. The engineer also stated that, he would revise his structural procedure to set performance criteria that would get him to (a)(1). However, the problem of no performance criteria for structures is a industry wide problem and has been identified before by NRC. The reason for the problem is that there is presently no industry guidance in this area. Inspector Followup Item No. 50-335,389/96-13-04 was identified by the inspector for the licensee to provide procedural guidance associated with performance criteria for structures after resolution of this issue with the industry.

- The main steam system was reviewed by the inspector to determine why the Unit 1 steam generators were in (a)(2) and not (a)(1) when they had caused a 40 day extension of the July 1996 outage and are scheduled to be replaced next refueling outage. The licensee's position for the steam generators not being in (a)(1) was that the major tube degradation that they are finding now was cause when the plant first went operational and sulfur was found in their secondary cooling water. This problem was corrected several years before the 3 year historical review required by the Rule and no other corrective action can be taken at this point that is not already being taken to correct this problem. Therefore, the licensee contends that further tube degradation is not maintenance preventable, but caused by the design of their steam generator supports and additional industry reviews are ongoing to support this theory. The licensee also stated that, the Unit 1 steam generators are tentatively schedule to be replaced during the next refueling outage. The inspector however, considered that sufficient historical data of degraded tubes existed for these generators to have been placed in (a)(1) and failure to do so was considered a program weakness.

The inspector interviewed the main steam system engineer, to obtain information on tube failures and the status of eddy current examinations and subsequent plugging activities. The inspector found that the system engineer for the main steam system has held the job for less than two months and although, the steam generators are listed as the major component in the main steam system, the risk significant portion of the steam generators and associated Maintenance Rules functions derived from the Technical Specifications are listed under the reactor coolant system. Neither the main steam nor the reactor coolant system engineer knew they had the steam generator tubes. However, both engineers had a basic understanding of the Maintenance Rule. During subsequent discussions, the Maintenance Rule Administrator stated that he considered as least the primary side and possibly the entire steam generator and should be under the reactor coolant system and that he intended to change the program to reflect this. The inspector however, considered the lack of ownership of the steam generator tubes to be a weakness in the licensee's program.

c. Conclusions

The inspector concluded that the licensee had selected the correct structures to be monitored under the Maintenance Rule and had established a systematic program for monitoring the condition of these structures. However, Inspector Followup Item 50-335,389/96-13-04 was identified for the licensee to provide procedural guidance associated with performance criteria for structures after resolution of this issue with the industry.

The licensee also contends that present steam generator tube degradation is not caused by a maintenance preventable functional failure but by the design of their steam generator supports and additional industry reviews are ongoing to support this theory. The inspector however, considered that sufficient historical data of degraded tubes existed for these generators for them to have been placed in (a)(1) and failure to do so was considered a program weakness. In addition, the inspector considered the lack of ownership of the steam generator tubes to be a weakness in the licensee's program.

M2.1 Material Condition Walkdowns

a. Inspection Scope (62706)

In the scope of verifying the implementation of the Maintenance Rule using NRC Inspection Procedure 62706, the inspector performed a walkdown to examine material condition on portions of the Auxiliary Feedwater system.

b. Observations and Findings

The inspector's material condition walkdown of selected portions of Auxiliary

Feedwater system revealed that: housekeeping in the general areas around system and components was acceptable; piping and components were painted and no indications of corrosion, oil leaks, or water leaks were evident; and no damage, or degraded equipment was noted.

c. Conclusions

The material condition of selected portions of the Auxiliary Feedwater system examined during the inspection was satisfactory.

E2.1 Review of UFSAR Commitments

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, procedures and/or parameters.

E4.1 Engineer Knowledge of Maintenance Rule

a. Inspection Scope (62706)

The inspectors interviewed licensee engineers within the system engineering organization to assess their understanding of the Maintenance Rule and associated responsibilities.

b. Observations and Findings

The System Engineer for the RCP seals and the civil engineer for structures had considerable engineering experience and knowledgeable of their assigned area. The system engineer for the RCP seals been proactive in development and implementation of corrective actions. Both of these engineers had been active participants in the development of the Maintenance rule criteria (including procedures for the civil engineer) for their systems. The system engineers for AFW and the main steam systems are newly assigned to these systems and lacked some of the historical information for their assigned systems. The AFW system engineer had been a system engineer for another system two months prior to the inspection and had a better much better understanding of the Rule and his system than the main steam system engineer. All the engineers interviewed by the inspector understood the specific requirements of the Maintenance Rule. However, the performance criteria for the AFW and the main steam systems had been developed for the system engineers prior to their system assignment.

c. Conclusions

All engineers interviewed by the inspector knew the specific requirements of the rule. Two of the system engineers had only had their systems two months prior to the inspection. The system engineers for the Auxiliary Feedwater System and the Main Steam System lack some historical information for their assigned systems.

Documents received from the licensee during conduct of my inspection activities

1. Palo Verde Plant Update (Technology Transfer) dated September 19,1996

2. St. Lucie Unit 1 and 2 Steam Generator Plug Status
3. St. Lucie Condition Report No. 96-2037 (Steam Generator Tube degradation)
4. St. Lucie Unit 1 Steam Generator Eddy Current & Tube Plugging History
5. St. Lucie Condition Report 96-598 (RCP 1A2 Pump Seal)
6. RCP 1A2 Seal Root Cause Analysis Dated August 25, 1993
7. St. Lucie STAR 1-950988
8. St. Lucie ADM-17.03 Revision 6 "Operating Experience Feedback"
9. NUMARC 93-01 Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"
10. St. Lucie Plant SCE Problem Report 95-017, (RCP 2A2)
11. St. Lucie Plant Maintenance Rule Periodic Assessment (Draft)
12. Scoping Document for the Implementation of the Maintenance Rule for Monitoring the Effectiveness of Maintenance on Structures, Rev. 2

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INSPECTOR'S INPUT

St. Lucie 96-08

A. Inspector Concurrence: ______________________ ____________
J. L. Coley, Jr. Reactor Inspector

Branch Chief Concurrence: ______________________________
P. E. Fredrickson, Branch Chief
Special Inspection Branch

B. 1.0 Persons Contacted

*E. Benkien, Licensing Engineer
*W. Bladow, Site Quality Manager
*C. Burton, Site Service Manager
*F. Carr, Nondestructive Examination, Technical Specialist
*J. Connor, Manager, Components and Systems Inspection
*D. Denver, Manager, Engineering
*R. Dietz, Licensing Engineer
*H. Johnson, Manager, Operations
*J. Marchese, Manager, Maintenance
*J. Scarola, Plant General Manager
*E. Weinkam, Manager, Licensing

Other licensee employees contacted during this inspection included technicians, and engineers.

C. Input for appropriate inspection area.

3.0 Maintenance

3.1 Observation of Inservice Inspection Work Activities - Unit 1 (73753)

This inspection is a continuation inspection, see NRC Inspection Report 96-06 for additional details involving this area of examination.

On May 13, 1996 the inspector returned to the St. Lucie facility inspector to observed inservice inspection activities and to determine if these activities are conducted in accordance with applicable procedures, regulatory requirements, and licensee commitments. The inspector's objective was to examine the licensee's steam generator examination and evaluation activities and the 10-year ultrasonic examination of the reactor vessel. The applicable code for this ISI is the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, 1983 Edition with Summer 1983 Addenda. St Lucie Unit 1 is presently in the first outage of the third 40 month period, of the second 10-year ISI interval. This is the thirteenth refueling cycle.

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Eddy current acquisition activities were conducted by ASEA. Brown & Boveria INC (ABB)/Combustion Engineering. Primary analysis of eddy current data was conducted by Zetec in Issaquah, Washington and the secondary analysis was conducted by ABB at the Florida Power and Light NDE Laboratory in West Palm Beach, Florida. The 10-year Reactor Vessel examinations were conducted by Southwest Research Institute.

3.1.1 Observation of Steam Generator Eddy Current Acquisition and Data Analyses Activities

On May 13, 14, and 16, 1996, the inspector observed portions of the licensee's eddy current data acquisition activities. These activities were conducted in accordance the with approved procedures delineated in NRC Inspection Report No. 96-06 and the FP&L Steam Generator Eddy Current Examination Plan. On May 15, 1996, the inspector went to FP&L's NDE Center in West Palm Beach, Florida to examine FP&L's eddy current analyses activities. These activities were also conducted in accordance with approved procedures and industry guidelines delineated in NRC Inspection Report 96-06. At this point of the inspection the licensee had identified numerous rejectable indications. However, some of the rejectable indications were found in areas where they were not expected. These areas included two tubes which exhibited circumferential cracking at the top of the tube sheet in the A Steam Generator Cold Leg. This will require the cold leg side of both steam generator to be examined 100% with a motor rotating pancake coil. In addition, an axial indication was found in the free span area between support plates 7 & 8. This is an area of concern that will require expansion examinations because there is no inherent condition which should cause crack initiation in this area. As a result of the present expansion examinations the licensee has added approximately a week to the steam generator eddy current and plugging activities.

The inspector also reviewed qualification and certification records for all eddy current personnel. In addition, equipment calibration records were verified.

During the inspection period the inspector was also a party to NRC's Office of Nuclear Reactor Regulations (NRR) telephone calls with the licensee. These calls dealt with FP&L's steam generator tube inspection plans, tube expansion plans, in-situ pressure testing plans and tube plugging plans. The licensee was pro-active in keeping NRR informed of their inspection findings and correction action plans and all actions taken by the licensee at this point appeared to be conservative.

During the next refueling outage (Cycle 14) the licensee intends to replace the steam generator tube bundles in both Unit 1 steam generators.

3.1.2 Observation of Work Activities Associated with the 10-Year Inservice Inspection of the Unit 1 Reactor Pressure Vessel

As a result slippage in the defueling schedule the ultrasonic examinations of reactor vessel were not conducted during this inspection period. However, as partially reported in NRC Inspection Report 96-06, the inspector did reviewed the applicable nondestructive examination procedures, visited the Electric Power Research Institute (EPRI) in Charlotte, N.C. to review EPRI's methods of testing for one sided access examinations, reviewed analyst performance demonstration qualification records, verified ultrasonic equipment calibration records, and verified the setup of the ultrasonic system both in the plant and in the remote acquisition and analysis station.

During the inspector May 10, 1996 visit to the EPRI NDE Center (as report in NRC Inspection Report No. 96-06) the inspector was surprised to find that the qualification examinations given for one sided weld access examinations were conducted on test samples which did not have a weld joint in them. The inspector was concern that the demonstration test did not accurately depict plant conditions because the acoustical differences of the weld metal and the base material which should have some limiting effects on the examination. In addition, the differences in the lay of defect indications on far side of the welds had not been addressed by EPRI even in an analytical manner. EPRI position was that, in their opinion the missing weld would not make a <u>significant difference</u> in the detection and sizing of indications in the carbon steel reactor vessel. Although not disagreeing with EPRI, the inspector felt that the difference should be defined and factored into the difficultly of the single side weld access performance demonstration test, and actual reactor vessel examinations if necessary.

On May 13, 1996, when the inspector returned to the St. Lucie plant, the above issue was discussed with FP&L licensing and NDE personnel. As a result of these discussions the licensee offered the following response to this item.

"FPL Response: We contend that a weld is not necessary in carbon steel vessel material. Because this is a completely isotropic medium which has minimal influence on the passage of ultrasonic waves. We intend to prove this by the following:

- As a member of the Performance Demonstration Iniative (PDI), FPL has initiated action at the EPRI NDE Center to address the issue. The PDI program was used to conduct the demonstration therefore it is incumbent of them to defend their position. We expect them to produce empirical data from previous study or a demonstration to show that the presence of a weld in vessel material is insignificant.

OR/

The examination contractor (Southwest Research Institute) will look at producing similar empirical data form their studies. If necessary, will measure ultrasonic beam attenuation in similar material with and without a weld".

- The licensee also stated they would assign a licensing No. to this item to insure that the issue is properly tracked and that a copy of the result, would be forwarded to the inspector.

The inspector considered the licensee actions to be responsible and adequate to resolve this concern.

D. 7.0 Exit Meeting

The inspection scope and results were summarized on May 17, 1996, during a pre-exit meeting with the licensee. The inspector described the areas inspected and discussed in detail the inspection results which included FPL's response to the inspector concern that EPRI's performance demonstration qualification test samples did not include a weld for one sided access weld examinations. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

E. 8.0 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with the UFSAR commitments. During an approximate two month time period all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices, procedures, and/or parameters.

While performing the inspections which are discussed in this report the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

F. 9.0 Acronyms

ABB - ASEA, Brown and Boveria
ASME - American Society of Mechanical Engineers

B&PV	-	Boiler & Pressure Vessel Code
EPRI	-	Electric Power Research Institute
FP&L	-	Florida Power and Light
NDE	-	Nondestructive Examination
NRC	-	Nuclear Regulatory Commission
NRR	-	Office of Nuclear Reactor Regulations
PDI	-	Performance Demonstration Iniative
UFSAR	-	Updated Final Safety Analysis Report

G. 10.0 Summary Statement

The licensee's inservice inspection activities for the steam generator tube eddy current examination activities and the 10-year reactor vessel examinations were well planned, performed, and managed by very talented and knowledgeable NDE personnel. No violation or adverse tend was noted in any area examined.

INSPECTOR INPUT TO INTEGRATED INSPECTION REPORT

St. Lucie

INPUT FOR INSPECTION REPORT NO.: 50-335,389/96-14

INSPECTOR: James L. Coley, Jr.
Reactor Inspector, Special Inspection Branch
Division of Reactor Safety

DATES OF INSPECTION: No onsite inspection performed. This input documents actions taken by the Florida Power and Light (FP&L) and the Electric Power Research Institute's (EPRI), Nondestructive Evaluation Center in Charlotte, North Carolina to address an inspector's concern regarding one sided weld inspections performed on the Unit 1 reactor vessel in May 1996. FP&L forwarded EPRI letter on above subject on August 15, 1996.

Inspector: ______________________________ ____________
James L. Coley, Jr. Reactor Inspector Date Signed

Approved: ______________________________ ____________
P.E. Fredrickson, Chief Date Signed
Special Inspection Branch
Division of Reactor Safety

1.0 Persons Contacted:

Licensee Employees

T. Quinlen, Regulatory Compliance Engineer

M8 Miscellaneous Maintenance Issues

M8.1 Significance and Effect of Weld Volumes within ASME Section XI, Appendix VIII, Supplement 4 and 6 Performance Demonstration Test Specimens

Although the Authorized Nuclear Inspector (ANI) for Florida Power and Light (FP&L) had approved single side weld examination techniques demonstrated by Southwest Research Institute (SwRI), nondestructive test (NDE) examiners at the Electric Power Research Institute, the inspectors had questions concerning single side weld access test parameters and examiner's performance that could only be addressed at the EPRI NDE Center (see Region II Inspection Report 96-06 for further details).

On May 10, 1996, the inspectors and a representative from FP&L visited the EPRI NDE Center in Charlotte, North Carolina, to review the performance demonstration examination results for the four Southwest Research Institute data analysts that would be used by FP&L to examine the Unit 1 reactor vessel. This review was necessary because FP&L's Relief Request entitled, "Request for Authorization of Alternative Examination Methods" had two alternative examinations proposed by the licensee that had changed since NRC had originally approved the relief

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request. The relief request addressed Unit 1 reactor pressure vessel welds which had limiting conditions that prevented 100% examination coverage.

The first change was that the licensee had initially stated that a full vee 45° shear wave examination would be performed to the extent practical to compensate for recorded limitations. However, SwRI examination procedures did not have this examination method in them.

The second change to the April 1995 Relief Request stated that, FP&L would employ, as they became available, additional examinations, inspections and/or techniques that would provide a substantial increase in the examination of areas currently missed under the current examination techniques.

To comply with their commitment to employ examination techniques that provide a substantial increase in the examination of weld areas currently missed, FP&L had SwRI qualify to the performance demonstration examinations conducted by the EPRI NDE Center for a single side weld access examination. These examinations are to be conducted in accordance with Appendix VIII of later editions of the ASME Code. The editions of the Code which include Appendix VIII have not been approved for use by NRC at this time. The applicable ASME Section XI Code presently requires that a weld be examined from two directions (both sides of a weld). Therefore, to supplement the Unit 1 Reactor Vessel examinations with these new alternative techniques the licensee invoked paragraph IWA-2240 of the applicable ASME Code which states that, "alternative examination methods, or newly developed techniques may be substituted for the methods specified provided the ANI is satisfied that the results are demonstrated to be equivalent or superior to those of the specified method".

During the inspectors visit to the EPRI NDE Center the inspectors identified that the qualification examinations given for one sided weld access examinations were conducted on test samples which did not have a weld joint in them. The inspectors were concerned that the demonstration test did not accurately depict plant conditions because there are acoustical differences between weld metal and base material which could effect the results of the examinations. In addition, the differences in the lay of defect indications on far side of the welds had not been addressed by EPRI even in an analytical manner. The EPRI position was that, the missing weld would not make a <u>significant difference</u> in the detection and sizing of indications in the carbon steel reactor vessel. Although not disagreeing with EPRI, the inspectors felt that the difference should be defined and factored into the difficultly of the single side weld access performance demonstration test, and actual reactor vessel examinations if necessary.

On May 13, 1996, the inspectors returned to the St. Lucie plant and the above issue was discussed with FP&L licensing and NDE personnel. As a result of these discussions the licensee offered the following response to this item:

FPL Response: "We contend that a weld is not necessary in carbon steel vessel material. Because this is a completely isotropic medium which has minimal influence on the passage of ultrasonic waves. We intend to prove this by the following:

- As a member of the Performance Demonstration Initiative (PDI), FPL has initiated action at the EPRI NDE Center to address the issue. The PDI program was used to conduct the demonstration therefore it is incumbent of them to defend their position. We expect them to produce empirical data from previous study or a demonstration to show that the presence of a weld in vessel material is insignificant.

OR/

The examination contractor (Southwest Research Institute) will look at producing similar empirical data form their studies. If necessary, will measure ultrasonic beam attenuation in similar material with and without a weld".

The licensee also stated they would assign a licensing No. to this item to insure that the issue is properly tracked and that a copy of the result, would be forwarded to the inspector.

On August 15, 1996, FP&L provided the inspectors an August 8, 1996, letter from EPRI to FP&L which addressed an evaluation conducted by EPRI to determine the significance and effect of weld volumes within ASME Section XI, Appendix VIII, Supplement 4 and 6 performance demonstration test specimens. The evaluation was conducted on a practice mockup. The material for practice specimen was obtained from the nozzle course of the same vessel that was used for the PDI PWR shell performance demonstration specimens. To facilitate the evaluation the original weld seam was identified by acid etch of the plate. An EDM notch and a side drilled hole were fabricated in the specimen at appropriate positions (Note: specimen ID and reflector dimensions are not used in this report to protect the identity of PDI practice and/or test mockups). Ultrasonic measurements were taken from both reflectors with the sound passing only through the plate material and then with the sound passing through the plate material and the weld seam. From the results obtained, the EPRI NDE Center reached the following conclusions:

- Comparison for the attenuator/amplitude measurements from both the hole and the notch indicate the weld seam does not have any measurable effect on the amplitude of an ultrasonic reflector.

- Plotting of the ultrasonic beam indicates the beam continues in a straight line and is not redirected by the weld seam.

The inspector considers actions taken by FP&L and EPRI regarding the inspector's concern to be responsible and adequate. This issue is considered closed.

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