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Maintenance Branch
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EXECUTIVE SUMMARY

Browns Ferry Nuclear Plant, Units 1, 2, and 3
NRC Inspection Report 50-259/97-04, 50-260/97-04 and 50-296/97-04

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 Region II.

Overall, the inspection team concluded that the licensee had a comprehensive Maintenance Rule program, and the program was being effectively implemented. The Team found only minor deficiencies in program implementation, which were immediately corrected by the licensee. These deficiencies were considered to be isolated occurrences. It was obvious that the licensee was staying abreast of recent industry developments and recent NRC inspections at other nuclear facilities, and was taking action to strengthen their program concurrent with these activities.

Operations

- Licensed operators, in general, understood their specific duties and responsibilities for implementing the Maintenance Rule (Section O4.1).
- Licensed operators understanding of the risk matrix for removal of equipment from service was good (Section O4.1 and M1.2).
- Operator interviews indicated some confusion regarding interpretation of the risk matrix regarding Control Rod Drive and Residual Heat Removal crossover (Section O4.1).

Maintenance

- Required structures, systems, and components (SSCs) were included within the scope of the Rule for Units 2, 3 and Common (Section M1.1).
- The Team determined that the licensee's actions to implement the Rule for Unit 1 were technically adequate. However, an unresolved item was identified concerning Maintenance Rule implementation for Unit 1 (Section M1.1).
- Plans for performing the periodic evaluation met the requirements of the Rule (Section M1.3).
- The Maintenance Rule Assessment Report was a positive indicator of the licensee's implementation of the assessment process (Section M1.3).
- The approach to balancing reliability and unavailability was reasonable (Section M1.4).

- The licensee had considered safety in establishment of goals and monitoring for systems, and components in a(1) status (Section M1.6).

- Review of SSCs in a(2) status determined that performance criteria were adequately established commensurate with safety (Section M1.7).

- Industry-wide operating experience was used (Section M1.6 and M1.7).

- Adjustment of performance criteria and reevaluation of system performance, based on actual plant operating experience (as was the case with the Containment Isolation Valves and the Safety Relief Valves) demonstrated a proactive approach toward implementation of the Maintenance Rule (Section M1.6).

- The Team noted that baseline inspections had been completed on only two of 39 structures. An IFI was opened to follow licensee actions in this area (Section M1.7).

- In general, walkdown of systems determined that the systems were being adequately maintained (Section M2.1).

- Audits and self-assessments of the Maintenance Rule program were thorough and corrective actions were appropriately implemented (Section M7.1).

Engineering

- The licensee's overall quantitative approach to perform risk ranking for SSCs in the scope of the Maintenance Rule using the probabilistic risk assessment (PRA) approach was adequate (Section M1.2).

- PRA procedures in support of the Maintenance Rule were adequate (Section M1.2).

- The Expert Panel meeting held during the inspection showed careful consideration of the issues and was considered to be a benefit to the licensee's program (Section M1.2).

- The risk matrix and associated procedure for removal of equipment from service was considered good (Section O4.1 and M1.2).

- Some of the systems on the risk matrix were not well defined, the matrix did not provide PRA-related guidance for recovery from high risk configurations, and some risk significant systems were not included (Section O4.1 and M1.2).

- Systems engineers were knowledgeable of their systems, the Maintenance Rule, and how to apply the Rule to their systems (Section E4.1).

Report Details

Summary of Plant Status

Units 2 and 3 operated at power during the inspection period. Unit 1 was shutdown and defueled.

Introduction

The primary focus of this inspection was to verify that the licensee had implemented a maintenance monitoring program which met the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," (the Maintenance Rule). The inspection was performed by a team of inspectors that included a team leader and four Region II-based inspectors, and an NRC contractor. A Senior Reactor Analyst from Region II and an Operations Engineer from NRR observed the process to ensure inspection uniformity. The licensee provided an overview presentation of the program to the Team on the first day of the inspection. The overview handout is included as an attachment to this report.

I. OPERATIONS

O4 Operator Knowledge and Performance

O4.1 Operator Knowledge of Maintenance Rule

a. Inspection Scope (62706)

During the inspection, the Team interviewed three licensed reactor operators (ROs) and three licensed senior reactor operators (SROs) to determine if they understood the general requirements of the Maintenance Rule and their particular duties and responsibilities for its implementation.

b. Observations and Findings

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

- Determining SSC 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.

In general, the operators interviewed understood the philosophy of the Maintenance Rule and their responsibilities associated with the rule. All indicated a strong emphasis on returning equipment to service as soon as possible, in order to minimize

SSC unavailability. Also, all ROs indicated the need to document SSC outages in the control room log books for all SSCs under the scope of the maintenance rule. Finally, the ROs indicated that they make additional entries into the log books such that the system engineers can clearly identify the period during which the component was actually non-functional, distinct from the Technical Specification determination of equipment operability. This distinction is especially important for the emergency diesel generators.

The "Dual Unit Maintenance Matrix" in SSP 7.1 (Revision 16) provides guidance for evaluating the plant configuration risk for equipment out of service while the plant is at power. The SROs stated they use the matrix when emerging failures occur and occasionally to check work week activities. For cases where two SSCs may be taken out of service, the SRO's understanding of the matrix was good, except for some uncertainty in the interpretation of two of the systems on the matrix: Control Rod Drive (CRD) pumps and Residual Heat Removal (RHR) unit crossovers. For the CRD, there was uncertainty whether the CRD entry should be interpreted as both pumps or either pump. Also, for the RHR crossover events, the matrix entries appeared to be similar to matrix entries for the RHR trains (not involving crossovers between units). For cases where three SSCs on the matrix may be taken out of service, the SROs correctly stated that they would have to contact engineering (for PRA evaluation). Such guidance is stated on the matrix. Finally, for SSCs not listed on the matrix, the operators stated they use Technical Specifications, evaluations of "closeness to scram", and engineering judgment to decide if such SSC outages are risk significant.

c. Conclusions

In general, the ROs and SROs interviewed clearly understood the philosophy of the Maintenance Rule and their responsibilities for implementation of the rule. There was some confusion concerning the interpretation of several systems on the "Dual Unit Maintenance Matrix." However, there was no evidence that the confusion led to a high risk plant configuration.

II. MAINTENANCE

M1 Conduct of Maintenance

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

a. Inspection Scope (62706)

Prior to the onsite team inspection, the Team reviewed the Browns Ferry UFSAR, LERs, the EOPs, previous NRC Inspection Reports, and other information provided by the licensee. The Team selected an independent sample of SSCs that the Team believed should be included within the scope of the Maintenance Rule. SSC scoping criteria are described in 10 CFR 50.65 (b). During the onsite review, the Team used this sample and the 10 CFR 50.65 (b) criteria to determine if the licensee had adequately identified the SSCs that should have been included in the scope of the Browns Ferry 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. The expert panel reviewed the 162 systems in the plant and determined that 97 structures, systems, and components were in the scope of the Maintenance Rule.

The Team reviewed the licensee's SSC Selection and Performance Monitoring Matrix in an effort to verify that all required structures, systems, and components were included within the scope of the Maintenance Rule. The Team's review was performed to assure the scoping process included:

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

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

- Non-safety SSCs which are used in the plant emergency operating procedures

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

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

The Team verified that all required SSCs were included in the Rule for Units 2 and 3.

The Team reviewed the licensee's implementation of the Maintenance Rule on Unit 1 in a considerable amount of detail. This was necessary due to the fact that the licensee had considered plant status (i.e., Unit 1 is shutdown and defueled and has been for several years) in Rule implementation. The following information was obtained from this review:

- The licensee's Maintenance Rule implementing procedure (0-TI-0346) specifically stated that SSCs on Unit 1 had been scoped under the Rule considering plant status (i.e., shutdown and defueled).

- This procedure also stated that if Unit 1 conditions were to change scoping would be re-evaluated based on the change.

- The procedure referenced a letter regarding Unit 1 status, which includes specific commitments to notify NRC of any plans to return the unit to operation and also to obtain Commissioners' approval prior to restart of the unit (Reference April 16, 1996, letter from President, TVA Nuclear and Chief Nuclear Officer, (A00 960415900) to the US Nuclear Regulatory Commission).

- The procedure included a Maintenance Rule scoping matrix which provided a column for scoping of Units 2, 3, and common, and a separate column for scoping Unit 1 only.

- Unit 1 systems which support Unit 2 and 3 operation, and Unit 1 systems which interface (are common) with Unit 2 or 3 were properly scoped in the Rule, as appropriate. Active performance monitoring, data collection and trending was being performed on these systems.

- Unit 1 systems required to maintain safe shutdown of the unit, such as, spent fuel pool cooling were properly scoped in the Rule. Active performance monitoring, data collection and trending was being performed on these systems.

- Unit 1 systems which would normally be included in the scope of the Rule for an operating plant, such as High Pressure Coolant Injection, were not included in the scope of the Rule. Performance monitoring, data collection and trending was <u>not</u> being performed on these systems. These systems were in layup, not in use, and the licensee determined that normal Maintenance Rule monitoring was not appropriate.

The Team determined that the licensee actions to implement the Rule, based on the above facts, were technically adequate. However, the Team noted that other utilities with plants shutdown for considerable amounts of time had not considered plant status in implementation of the Maintenance Rule. This resulted in a question as to whether or not the approach taken by the licensee with respect to Unit 1 was in fact legal under the Maintenance Rule. This issue remained unresolved at the conclusion of the inspection. As a result, an Unresolved Item URI 50-290/97-04-01, Resolve Maintenance Rule Implementation on Browns Ferry Unit 1, is identified pending further NRC review.

c. <u>Conclusions</u>

The Team determined that the required structures, systems, and components were included within the scope of the Maintenance Rule for Units 2, 3, and Common. The Team also determined that the licensee's actions to implement the Rule for Unit 1 were technically adequate. However, an unresolved item was identified concerning Maintenance Rule implementation for Unit 1.

M1.2 Safety or Risk Determination

a. Inspection Scope (62706)

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

b. Observations and Findings

b.1 Risk Ranking

The licensee's process for establishing the risk significance of SSCs within the scope of the Maintenance Rule was documented in the TVAN Maintenance Rule 10 CFR 50.65 Program Manual, Revision 2, Section 3.4.2 and in the TVA BFNP Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 7, Section 7.1.2 and Appendix B. These documents were reviewed and found to be detailed, well-written, and found to provide good guidance for establishing the risk significance of SSCs.

For SSCs modeled in the licensee's Probabilistic Risk Assessment (PRA), three importance measures were evaluated (risk achievement worth, risk reduction worth, and core damage frequency contribution), as recommended in NUMARC 93-01. For SSCs with importance measures above the NUMARC 93-01 guidelines, the SSCs were determined to be risk significant. The licensee's Expert Panel did not change any of the SSC risk significances obtained from the PRA. The licensee's Expert Panel determined the risk significance of SSCs not modeled in the PRA, using an operator Delphi process for guidance.

The licensee used the latest versions of the PRA to evaluate SSC importance measures. These versions are the May 1996 PRA (Unit 2 with Unit 3 Operating) and June 1996 PRA (Unit 3 with Unit 2 Operating). In these PRAs, the licensee stated that the sequence truncation level was approximately 1E-11/y. The Team believes that this truncation level is low enough to result in accurate SSC importance measures, given the large event tree process used in the PRAs.

Based on the reviews discussed above, the Team determined that the licensee's approach to establishing the risk ranking for SSCs within the scope of the Maintenance Rule was adequate.

b.2 Performance Criteria

The Team reviewed the licensee's performance criteria to determine if the licensee had adequately set performance criteria under (a)(2) of the Maintenance Rule consistent with the assumptions used to establish the safety significance. Section 9.3.2 of NUMARC 93-01 recommends that risk significant SSC performance criteria be set to assure that the availability and reliability assumptions used in the PRA are maintained.

The licensee's approach to establishing performance criteria was outlined in the TVAN Maintenance Rule 10 CFR 50.65 Program Manual, Revision 2, Section 3.4.3 and TVA BFNP Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 7, Sections 7.1.3 and 7.3.

The performance criteria were presented in the system attachments to the BFNP Technical Instruction 0-TI-346. In general, the licensee stated that the performance criteria were established by using the PRA values as initial estimates, with the system engineers making the final decisions. The licensee stated that the system engineers had two years of past performance to help them decide if the PRA values were appropriate. (The BFNP PRA models for Units 2 and 3 still have a significant amount of generic input to the SSC unavailabilities and unreliabilities. The licensee stated that plant-specific information will be used in the BFNP PRA updates, to be performed in 1998.) In general, the PRA unavailabilities were used as performance criteria, unless they were considered to be too high based on plant experience. However, some performance criteria were chosen to be significantly higher than the PRA values. To determine the safety significance of these changes, the licensee reevaluated the PRA using the Maintenance Rule unavailability performance criteria to determine the impact on the core damage frequency.

For unreliability performance criteria, the licensee used functional failures (FFs) rather than maintenance preventable functional failures (MPFFs). The FF performance criteria are generally one or two per 24-month rolling average period. For risk-significant systems, one failure per train was used, while for non-risk-significant systems, two failures per train were used. Because of the limited demands for most systems during a 24-month period, the unreliability performance criteria were, in general, much higher than corresponding values in the PRA. In order to evaluate the effects on the PRA of these unreliability performance criteria, the licensee estimated demands for each train, converted the performance criteria to failure probabilities and input them into the PRA to determine the impact on the core damage frequency. The licensee reevaluated the SSC importance measures using these higher unreliabilities to ensure that the risk significance determinations discussed in Section b.1 were not affected.

The changes in core damage frequency when all of the unreliability performance criteria were input into the PRA are significant for both Units 2 and 3. The licensee stated that several things prevent the plant from approaching these higher core damage frequencies: (1) it is unlikely that all of the SSCs would approach the

Maintenance Rule unavailability and unreliability performance criteria at the same time (or over a 24-month period); (2) even if the performance criteria were approached in a 24-month period, the PRA methodology of using a Bayesian update to process these plant-specific data would result in smaller core damage frequency increases (until at least several 24-month periods in a row had high unavailability and unreliability data); (3) effective Maintenance Rule implementation should result in reduced unavailabilities and unreliabilities compared with past performance; and (4) the periodic (every 2 outages, or approximately 3 years) updating of the PRA (Standard Engineering Procedure SEP-9.5.8) would indicate an upward trend in core damage frequency, which would feed back into the re-establishment of more stringent performance criteria. The Team agreed that these factors should help to limit potential core damage frequency increases.

Finally, the Team noted that the licensee was using plant performance criteria for several risk-significant, normally-operating SSCs (e.g., Reactor Feedwater and Condensate). For these SSCs, pump trains can be unavailable while the plant is at power. However, the plant would have to operate at reduced power. In such cases, plant performance criteria would typically be inappropriate for adequate monitoring of train FFs and unavailabilities. However, the licensee's methodology essentially used the plant performance criteria to trigger a more detailed evaluation of the FF or unavailability (reduced power event) which essentially resulted in system level monitoring. Also, because the performance criteria associated with these systems were much lower than the PRA values, monitoring on a system level, rather than a train level, was judged to be adequate. The licensee stated that if one train were experiencing most of the FFs or unavailability, then their trending analysis would trigger an examination of the problem. The Team agreed with the licensee's approach to monitoring these systems.

b.3 Expert Panel

The Team reviewed the licensee's process and procedures for establishment of an Expert Panel. It was determined that the licensee had established an Expert Panel in accordance with the guidance provided in NUMARC 93-01. The Expert Panel's responsibilities included the final authority for decisions regarding maintenance rule scope, risk significance, performance criteria selection, moving SSCs from (a)(2) status to (a)(1) status and vice versa, and balancing of unavailability and unreliability.

The Team observed an Expert Panel meeting involving the consideration of changes to performance goals and the revision of the BFNP Technical Instruction 0-TI-346. The Expert Panel's discussions were detailed and thoughtful. The Team also reviewed the training requirements and process for training the members of the Expert Panel. Finally, the Team reviewed the minutes of recent Expert Panel meetings. Overall, the Team considered the Expert Panel performance to be a strength.

c. Conclusions

Based on the Team's reviews discussed previously, the licensee's approaches to risk ranking and performance criteria selection appeared to be appropriate. Also, the Expert Panel's performance was considered to be a strength.

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 Team reviewed the procedure the licensee had established to ensure this evaluation would be completed as required. In addition, the Team discussed the requirements with the Maintenance Rule Coordinator who is responsible for this activity.

b. Observations, Findings and Conclusions

Plans for performing the periodic evaluation met the requirements of the Rule. In addition, the periodic report of system performance was considered a positive indicator of the licensee's implementation of the assessment process.

M1.4 Balancing Reliability and Unavailability

a. Inspection Scope (62706)

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 Team met with Maintenance Rule Coordinator, system engineers, and representatives of the Expert Panel to discuss the licensee's methodology for balancing reliability and unavailability.

b. Observations and Findings

The Team reviewed the licensee's approach to balancing system reliability and unavailability for risk significant systems to achieve an optimum condition. The licensee had scheduled balancing reviews during periodic evaluations at refueling outages, not to exceed 24 months. The requirements for balancing reliability and unavailability were discussed in the licensee's administrative procedure 0-TI-346, Maintenance Rule Performance Indicator Monitoring. Trending, and Reporting - 10 CFR 50.65, Revision 7. System engineers were responsible for the balancing process for risk significant systems during periodic system evaluations. Additionally,

the system engineers were required to monitor and trend the system performance continuously. Should an adverse trend be identified the system engineer was responsible for initiating an evaluation at that time.

The licensee's procedure indicated the method for balancing was to monitor against the individual system unavailability and reliability performance criteria values. Those values were based on the PRA assumptions which took into account an optimum value relative to core damage. If these performance criteria were exceeded, the cause determination would assess the appropriateness of planned maintenance activities or the root cause of the failure and its impact on reliability. Since the individual system performance criteria were judged to be appropriate, the Team determined the balancing method met the intent of the MR.

The Team reviewed nine risk significant functions (systems) that required a balancing analysis. The balancing analysis was needed since the performance criteria of either reliability or unavailability was exceeded. Two functions exceeded the unreliability criteria. Six functions exceeded the unavailability criteria. One function exceeded both the unreliability and unavailability criteria. Three of the functions were classified as (a)(1). The other six functions were classified as (a)(2). The Team verified that the data for both reliability and unavailability was monitored, analyzed, and trended for performance over a rolling 24-month period of time. For reliability, for pumps, valves and other components, demands and failures were monitored on a monthly basis. The required, planned, and unplanned unavailability was also monitored and trended on a monthly basis. Failures were identified as functional failures and maintenance preventable functional failures. No repetitive failures were identified. The Team concluded the licensee analyzed these nine functions properly for balancing reliability and unavailability.

c. Conclusions

The Team concluded that the licensee's method of balancing reliability and unavailability met the intent of the Maintenance Rule. In addition, the licensee's methods for monitoring, analyzing, and trending the data were appropriate.

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

a. Inspection Scope (62706)

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 Team reviewed the licensee's procedures and discussed the process with the PRA representative, the plant operators, and work-week managers.

b. Observations, and Findings

The Team reviewed the licensee's process and performance regarding their risk assessment of removing equipment from service. The process was documented in

Site Standard Practice SSP-7.1, Work Control, Revision 16, Appendix C for power operations and TVAN Standard Programs and Processes SPP-7.2, Outage Management, Revision 0, Appendix C when the plant is shut down.

When the plant is at power, the licensee stated that the "Dual Unit Maintenance Matrix" is used by the Work-Week Managers and SROs to evaluate plant risk for two risk-significant systems being out-of-service at the same time. The risk matrix was constructed using the PRA for guidance. However, the licensee stated that the 12-week rolling schedule and associated rules for what types of SSCs can be worked on each day of the week are the first line of defense against risk-significant concurrent SSC outages. After the work-week is planned using that guidance, then the Work-Week Managers and SROs evaluate risk using the matrix. The licensee stated that most use of the matrix involved the evaluation of emergent work. Generally, no record of uses of the matrix is kept. The licensee stated that a record would be kept only if a risk-significant concurrent SSC outage was approved and actually occurred.

The risk matrix does not cover concurrent outages of three or more SSCs. In such cases the matrix instructs the Work-Week Managers and SROs to contact engineering to obtain a PRA evaluation of the plant risk.

Three weaknesses of the risk matrix were identified by the Team. First, the matrix does not include all risk significant SSCs. For example, Reactor Feedwater is not on the matrix. Second, the matrix does not provide PRA-related guidance (which SSC to concentrate on) for recovery from high risk configurations. Finally, the Team thought several of the matrix system entries were unclear. In interviews with SROs, the Team found that the CRD and RHR crossover entries were being interpreted inconsistently. It should be noted that the licensee issued Problem Evaluation Report (PER) BFPER970694 to address this problem during the inspection week.

The procedures used by the licensee for plant shutdown conditions appear to be the standard industry approach, based on NUMARC 91-03, INPO guidelines for outage management, and EPRI guidance. In addition, the licensee stated that the OUTAGE RISK ASSESSMENT MANAGEMENT (ORAM) was used to evaluate plant risk from the planned outage activities and from the actual outage activities.

c. Conclusions

The Team viewed the licensee's process for assessing plant risk resulting from multiple equipment outages to be appropriate. The tool used to assess plant risk while at power, the risk matrix, was generally good. However, weaknesses of the matrix included the omission of several risk-significant SSCs, failure of the matrix to provide PRA-related guidance for recovery from high risk configurations, and the lack of clarity in several of the risk matrix entries.

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

a. Inspection Scope (62706)

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

The Team reviewed selected systems and components for which the licensee had established goals for monitoring of performance to provide reasonable assurance the system or components were capable of fulfilling their intended function. The Team evaluated the use of industry-wide operating experience, monitoring of SSCs against goals, and corrective action taken when SSCs failed to meet goal(s), or when a SSC experienced a MPFF.

The Team reviewed program documents and records for the three systems or components the licensee had placed in the (a)(1) category in order to evaluate this area. The Team also discussed the program with the Maintenance Rule coordinator, system engineers, and other licensee personnel.

b. Observations and Findings

b.1 Primary Containment Isolation Valves

The licensee had recently revised the performance criteria for System 64A, Primary Containment Integrity, to include additional criteria for measured as-found leakage on containment isolation valves. Local leak rate testing of containment isolation valves is required by TS and 10 CFR 50, Appendix J, and is normally performed during refueling outages. The new criteria was that no occurrences were allowed where an isolation valve failed its administrative limit on as-found leak rate testing during two consecutive testing periods. As a result, the licensee reviewed the as-found leak test data performed in October 1994 during the U2C8 outage and performed in April 1996 during the U2C9 outage. Unit 3 isolation valves were not considered during this licensee review because only one refueling outage has occurred since Unit 3 was restarted. The licensee determined that a total of five Unit 2 primary containment isolation valves had as-found leak rate test results which had not satisfied the revised criteria. These five valves were as follows:

- 2-FCV-1-14, Main Steam Isolation Valve
- 2-FCV-1-55, Main Steam Drain Isolation Valve
- 2-FCV-74-57, RHR Test Return Isolation Valve

- 2-FCV-75-54, Core Spray Testable Check Valve

- 2-FCV-75-57, Core Spray Torus Suction For PSC Head Tank Pump Isolation Valve

The licensee's administrative limit for measured leak rate testing is less than or equal to the TS limit for each of these valves except for 2-FCV-74-57. Leak testing of this valve is required by 10 CFR, Appendix J to be performed to quantify leakage but no specific TS limit is provided for that valve. 2-FCV-74-57 is part of the RHR System which is considered an extension of the primary containment and therefore will not contribute to overall containment leakage. The Team determined that for each of the above failures that corrective actions had occurred and that leakage was below the administrative limit prior to Unit 2 startup from the respective outage.

The circumstances associated with the above five isolation valves were reviewed by the expert panel on March 5, 1997, and resulted in movement of three of the isolation valves to (a)(1) classification. These valves were 2-FCV-1-55, 2-FCV-75-54, and 2-FCV-75-57. The Team reviewed the expert panel meeting minutes and other documentation provided by the licensee to verify the adequacy of the technical justification for leaving the remaining two isolation valves in (a)(2) status. The Team determined that the basis for the expert panel determination to place the three valves in (a)(1) status was the low significance of the actual measured as-found leakage and that the expert panel had considered the previous corrective actions as ineffective. The remaining two isolation valves had remained in (a)(2) status because the expert panel determined that the measured as-found leakage had not been a significant contributor toward the total calculated containment leak rate. Additionally, the corrective actions for those valves had been considered effective by the expert panel. The Team was informed that the expert panel determination to leave the two isolation valves in (a)(2) status was made based on the expectation that the established performance criteria would be satisfied during the next outage without additional corrective actions. The Team was further informed that the licensee would have to reconsider the effectiveness of previous corrective actions should any subsequent failures of those two valves occur. The Team concurred with the expert panel decisions for each of these isolation valves.

Goals for the three isolation valves placed in (a)(1) status were to be established by the licensee as part of the corrective actions associated with PER BFP970580. The corrective actions for this PER were still being developed by the licensee at the time of the inspection. The Team reviewed PER BFP970580 and determined that the licensee's proposed goals included two options. The first option was a requirement that the valves must successfully pass their as-found leak rate test during the U2C10 outage if the subject valves were replaced with a new valve of a type that has performed successfully in similar service. The second option was that, if not replaced, the existing valves must have passed two successive as-found leak rate tests following the upcoming U2C10 outage. One of these two options must have been satisfied prior to movement of the individual valves back to (a)(2) status. The Team determined that the licensee has considered safety in establishment of monitoring for these SSCs. Proposed corrective actions and goals were appropriate. The System

Engineer was knowledgeable of assigned system and had been proactive in development and implementation of proposed corrective actions.

b.2 ECCS Analog Trip Unit Inverters - Unit 3

The risk significant Unit 3 ECCS analog trip unit inverters were classified as (a)(1). The performance criteria of no more than one functional failure per unit during a rolling 24-month period was exceeded. The following functional failures for Unit 3 inverters occurred over a rolling 24-month period: 1) July 17, 1996, DIV I, Fuse FU1 cleared and SCR2/D2 shorted; 2) August 6, 1996, DIV I, Fuse FU1 cleared and SCR1/D1 shorted; 3) November 6, 1996, DIV I, Fuse FU1 cleared; 4) October 13, 1996, DIV I, Fuse FU1 cleared; and 5) December 17, 1996, DIV II, Fuse FU1 cleared and SCR2/SD2 shorted.

The licensee attributed the failures in Unit 3 to defective SCRs (silicon controlled rectifiers). Problem Evaluation Report No. BFPER960925 addressed the inverter failures. In this PER, the licensee's SCR expert contractor stated that "all evidence presently available suggests that these failures were related to an over-voltage condition". However, the engineering personnel believed that the batch of SCRs (1993 period) used in the Unit 3 inverters were defective since there were no similar failures with the same type of SCRs (1990 period) in the Unit 2 inverters. All new SCRs were installed in the Unit 3 inverters. In addition, an alternate backup power supply was installed for each of the ECCS inverters. The backup power supply installation was completed in accordance with plant modification ECN/DCN/WO T39853 dated February 28, 1997. Therefore, even if an inverter fails, the backup power supply would still provide power to the analog trip units. A similar modification was planned for Unit 2 during the next refueling outage.

Initially the licensee's goal for returning the Unit 3 inverters to (a)(2) status were no functional failures and no unplanned unavailability for the next six months beginning April 1, 1997. The Team questioned this goal and informed the licensee that the length of monitoring in this goal was less stringent than the time period for the first failure. The first inverter failure occurred 10 months after it was placed in operation, and the second inverter failure occurred 14 months after it was placed in service. As a result, the expert panel re-evaluated the established goal and revised it to monitor for failures over an 18-month period. The Team concluded this goal was more appropriate and met the intent of the Maintenance Rule.

b.3 Main Steam Safety Relief Valves

The Main Steam System consists of 13 main steam safety relief valves (SRVs) which provide overpressure protection of the reactor coolant pressure boundary, as well as manual initiation of the Automatic Depressurization function and manual pressure control during emergency conditions. The licensee placed this system in the (a)(1) status, based on the performance of the SRVs during a Unit 2 reactor trip in October 1996, and continuing problems with setpoint drift. Analysis of that trip indicated that all 13 SRVs failed to lift when reactor pressure peaked at approximately 1130 psig. Subsequent replacement and testing indicated that all valves had as-found setpoints

less than 1250 psig, which at that time was defined as the basis for functional failure for the Maintenance Rule. Although the SRVs did not exceed the Maintenance Rule criteria, the licensee determined that the performance of the SRVs, and performance criteria, was less than adequate. The licensee's operating/test data, combined with industry data, indicated that a setpoint drift resolution based on a catalytic alloy (platinum-stellite) approach already in place at Browns Ferry, did not appear to be effective. The licensee initiated PER BFPER961764 to document a corrective action plan and revise goals and performance criteria to insure the overpressure protection function of the SRVs. Unit 3 SRVs were also placed in (a)(1) status at that time.

The Team reviewed the licensee corrective action plan, and considered it to be appropriate. In addition, the revised goals and performance criteria for the SRVs had appropriately considered safety. The Team also considered the placement of the main steam SRVs in (a)(1) status after evaluation of actual plant data demonstrated a proactive Maintenance Rule initiative.

c. Conclusions

The licensee had considered safety in establishment of goals and monitoring for systems, and components in a(1) status. Industry-wide operating experience was used and corrective actions were appropriate. The Team concluded that adjustment of performance criteria and reevaluation of system performance, based on actual plant operating experience (as was the case with the CIVs and the SRVs) demonstrated a very proactive approach toward implementation of the Maintenance Rule.

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

a. Inspection Scope (62706)

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

The Team reviewed selected SCCs for which the licensee had established performance criteria and was trending performance to verify that appropriate preventative maintenance was being performed, such that the SSCs remain capable of performing their intended function. The Team evaluated the use of industry-wide operating experience, trending of SSCs against performance criteria, and corrective action taken when SSCs failed to meet performance criteria, or when a SSC experienced a MPFF.

The Team reviewed program documents and records for selected SSCs the licensee had placed in the (a)(2) category in order to evaluate this area. The Team also discussed the program with the Maintenance Rule coordinator, system engineers, maintenance supervisors, and other licensee personnel.

b. Observations and Findings

b.1 Structures

The licensee's program for Buildings and Structures, as defined in Attachment 38 to site Technical Instruction 0-TI-346, addressed all site Buildings and Structures and identified 39 within the scope of the Maintenance Rule. Condition-based performance and monitoring criteria had been established for trending the performance of the Structures in scope and re-classifying the structures from (a)(2) to (a)(1) as appropriate. During review of the licensee's performance criteria for structures, the Team noted that an unacceptable condition, which is the basis for evaluating the need for moving a structure from (a)(2) to (a)(1), was established by the licensee as degradation such that a Structure is "incapable of performing its structural function." Revision 2 of RG 1.160 considers a Structure that has degraded "to the extent that the structure may not meet its design basis" as the basis for moving a Structure from (a)(2) to (a)(1). This issue was pointed out to the licensee. Prior to the end of the inspection, the licensee changed procedure 0-TI-346 to agree with the RG relative to structures meeting the "design basis". After this change, the Team determined the performance criteria to be adequate.

At the time of the inspection, only 2 of the 39 Structures (Unit 3 Drywell and Unit 3 Emergency Diesel Generator Building) had received a baseline walkdown inspection to document the initial condition. The Team selected the Unit 3 Emergency Diesel Generator (EDG) Building for a more detailed review and walkdown inspection to verify the licensee's activities. Other than minor hairline cracking and spalding of concrete walls and floors, the licensee's inspection identified only one significant finding. This finding identified that a number of the water tight doors had gaps between the doors and the seals. Problem Evaluation Report (PER) BFPER970549 had been issued to document corrective action for this condition. The PER included an operability evaluation which concluded that the building was operable with the doors not fully sealed. Based on preliminary work, the licensee found that the door piston assemblies might need adjustment to ensure proper sealing. The Team noted that inspection of the doors was included in the Preventive Maintenance (PM) program. The Team considered the corrective actions documented in the PER to be adequate. The Team's inspection of the building did not identify any deficiencies other than those documented by the licensee.

As noted above, the licensee had only completed the baseline walkdown inspection of two Structures. In addition, the licensee provided the Team a schedule for completion of the baseline walkdowns showing completion of the walkdowns by the end of 1998. The Team questioned the licensee relative to justification for having completed baseline walkdown inspections of only two Structures and not completing the inspections until the end of 1998. The licensee stated that their slow start for the Structures program was because of lack of issued guidance for performance monitoring of Structures. However, they considered previously completed inspection programs involving walkdown inspections of structures to provide evidence that structures are operable. These programs included: Drywell Steel Platforms, Miscellaneous Steel, Torus, TVA Welding Project, Concrete Verification, and Masonry

Block Walls. During the inspection, the licensee decided to modify their Structures program to take advantage of walkdown inspections from the previously completed programs and to complete the baseline inspections within the next six months.

The fact that so few Structures had been baselined under the Rule lead the Team identification of Inspector Followup Item (IFI) 50-259,260,296/97-04-02, Review of Maintenance Rule Baseline Results for Structures, in order to accomplish additional evaluation of the program after the licensee has completed additional inspections.

b.2 1A and 1B Shutdown Board HVAC

The 1A and 1B Shutdown Board HVAC System is a subsystem of System 31, HVAC Systems. Review of the this system determined this is a non-risk significant system which is under the scope of the Maintenance Rule. The 1A and 1B Shutdown Board Rooms are located in areas which are part of Unit 1, for which the licensee has no definite restart plans. However, these shutdown boards contain numerous Unit 2 electrical loads and are considered as shared equipment. The function of this system is to maintain the environment in the board rooms below 104°F required for protection of equipment and instruments necessary for safe plant operation. Air conditioning equipment for the 1A and 1B Shutdown Board Rooms and associated 480 VAC boards is designed to provide cooling during both normal operation and accident conditions. Each of these areas is cooled by a separate cooling unit located in the Unit 1 Reactor Building. Monitoring for the system consisted of trending environmental conditions in the board rooms from the shift operating logs. A functional failure of this system was defined as a failure of normal ventilation equipment to maintain the board rooms below 104°F. Additionally, the licensee's established performance criteria specified that a functional failure would have occurred any time temporary ventilation was required to be utilized to compensate for the inability of the normal ventilation to provide the cooling function.

Although this system has had a history of equipment problems no functional failures were included in the licensee's Maintenance Rule Data Base for this system. The Team discussed this issue with the system engineer and determined that the licensee's monitoring of this system was acceptable. The Team was informed that the heat load for these areas during an accident was not expected to exceed that of normal operating conditions. Review of the IPE HVAC System Notebook revealed that failure of the cooling to these areas had been shown not to lead to a failure of components in the affected areas. This determination was based on the plant's thermal analysis which indicated that the maximum temperatures in the shutdown board rooms during a 24 hour period following a loss of ventilation event would not exceed the limit. Additionally, the Team's review of operating logs for periods when the HVAC system was out-of-service revealed that significant increases in area temperature had not occurred. At no time was any limit approached while HVAC was unavailable.

The Team determined that the licensee had considered safety in establishing performance criteria and monitoring of this system. The system engineer was very knowledgeable of this system and was aware of the problems that has existed and the actions taken to resolve the problems.

b.3 Bus Duct Cooling System

Review of System 262, Bus Duct Cooling System, determined that this is a non-risk significant system and monitoring for the system had been established on a plant level basis. Performance criteria monitored included unplanned capacity loss (UCL) and unplanned or reportable safety system actuation. The criteria for UCL is no more than 2.2% per system or no more than three UCL events over a 24-month rolling interval, where a UCL event is defined as one that resulted, or could have resulted, in a reduction in power greater than or equal to 15% Rated MWE. There had been no scrams or reportable safety actuations associated with this system. There had been two UCL events on Unit 3 which had met the criteria. Additionally, there had been two unplanned power reductions on Unit 2 that had resulted in power reductions that were less than 15% rated MWE. However, the licensee had decided to track those events as UCL events so that the information would be readily available for future cause determinations in the event that additional future unplanned power reductions occurred.

The Team determined that the licensee had considered safety in establishing performance criteria and monitoring of this system. The system engineer was knowledgeable of this system and understood specific requirements of the Maintenance Rule and how to apply the rule to this system.

b.4 Emergency (Standby) Diesel Generators (EDG)

The EDGs were classified as a risk significant (a)(2) system. The performance criteria included both reliability and unavailability. For reliability, the individual performance criteria for each EDG was no more than three failures in the last 25 demands. The total reliability for all EDGs was no more than four failures in the last 50 demands or seven failures in the last 100 demands. The performance criteria each EDG shall maintain was an unavailability factor of less than 0.0342 over a rolling 24 months. Reliability of the 7-day fuel tank transfer pumps was monitored by no more than two pump failures in a rolling 24-month period.

The licensee had additional programs for monitoring the EDGs. These programs included "Station Blackout" requirements in Technical Instruction 0-TI-300, Emergency Diesel Generator Reliability Program, Revision 0. Technical Specification surveillance requirements were addressed in procedure 0-SI-4.9.A, Diesel Generator Reliability And Start Log Surveillance Instruction, Revision 4.

The Team reviewed and verified that reliability and unavailability were monitored through the use of 1) LCO Tracking Log, 2) Operations Log, 3) EDG Reliability and Start Log, 4) Diesel Generator Valid Failure Log, and 5) System Status (Health) Report. The Team also reviewed the reliability and unavailability monitoring charts.

The Team reviewed the licensee's corrective actions to improve overall performance of the EDGs. These corrective actions were found to be appropriate, and were being effectively implemented.

The Team concluded that the EDGs met their performance criteria and are properly classified as (a)(2). In addition, the licensee has good programs to monitor and trend the EDGs.

b.5 Turbine Generator Controls - EHC (Electro Hydraulic Control) System

The EHC systems for Units 2 and 3 were classified as risk significant (a)(2). The performance criteria for reliability was no more than one scram per unit over a rolling 24-month period. The performance criteria for unavailability was no more than 2 UCL events and each pump shall maintain an unavailability factor of 0.042 over a rolling 24-month period. The first Quarter 1997 System Status Report for Unit 2 identified one anomaly of a recurring oil leak on the plug for the 0.5 micron filters. The problem was addressed in BFPER 961526. The minor leak posed no threat to the performance criteria. During the walkdown, the Team did not observe any oil leaks of concern. The first Quarter 1997 Status Report for Unit 3 indicated there were no pressure excursions in the reactor dome pressure due to the EHC system although there was still a concern in this area. The pressure regulator control was swapped from channel A to channel B several times. The problem was determined to be signal drift with the bias adjustment. The problem and corrective action were addressed in BFPER961500. There was one other problem in Unit 3 resulting in a functional failure and unit trip.

Unit 3 had a functional failure that resulted in a reactor scram on February 2, 1996. Unit 3 scrammed due to a functional failure in the EHC system. The cause for this functional failure was identified as a defective tantalum capacitor on the Secondary Speed Control Voltage to Frequency printed circuit card. Corrective action for this failure was addressed in BFPER 960169. The card was replaced. No other failures had occurred and there was no other unavailability time during the last rolling 24-month period. The Team reviewed the system status (health) reports, work orders, Plant Level Event Reports, SCRAM Reports, the Expert Panel Meeting minutes for the EHC systems, EHC unavailability monitoring charts, and EHC reliability monitoring charts. The Team concluded the EHC system performance criteria was adequate and the (a)(2) classification was proper.

b.6 Reactor Water Cleanup

The Reactor Water Cleanup (RWCU) system was initially included in the Maintenance Rule on July 10, 1996. As a safety-related, non-risk significant system in continuous operation, the system was monitored at the plant level by the unplanned capacity loss factor, reactor trips, and safety system actuations. The purpose of this system is to provide and maintain appropriate reactor water chemistry.

The licensee had identified zero functional failures in the previous 24 months. The system had met its performance criteria and remains in (a)(2) status. The Team reviewed work orders, PERs, and other associated plant data, and determined that the licensee was appropriately monitoring this system consistent with Maintenance Rule requirements.

b.7 Reactor Building Zone and Refuel Zone Ventilation

As a safety-related, non-risk significant system in continuous operation, this system was monitored at the plant level by unplanned capacity loss factor, reactor trips, and safety system actuations. The safety-related aspect involves dampers which receive a primary containment isolation signal to provide secondary containment isolation such that the Standby Gas Treatment System would be able to perform its safety function. Maintenance Rule performance of the dampers is monitored as part of secondary containment. The licensee identified these dampers as continuously operating, because of the procedurally controlled weekly swapover of the supply and exhaust fans by Operations.

The licensee considered plant level monitoring to be appropriate for this ventilation system, because of the following: The licensee's plant safety analysis evaluation indicated that the probability of multiple damper failures coupled with the probability of a core melt event is so low as to be incredible. As such, the scoping of this system was non-risk significant. A complete loss of ventilation would result in a forced shutdown (prior to an automatic reactor trip) within one to two hours because of the affect on the main steam tunnel temperature switches. In addition, a loss of secondary containment (failure of both dampers in a penetration) would cause entry into a TS LCO, requiring a plant shutdown to begin if not restored within four hours. As such, the licensee considered plant level monitoring to be appropriate.

The Team discussed with the licensee the risk significance of secondary containment. The licensee stated that for an actual secondary containment breach to occur, it would involve failure of two sets of non-safety related dampers in each penetration (in addition to the two safety-related dampers). These non-safety related dampers are also cycled weekly by procedure. Based on this, the Team concluded that the risk significance associated with the function of these dampers, and the likelihood of failure of a single penetration (both safety-related dampers and both non-safety related dampers) during an accident, to be minimal.

The Team also discussed the licensee's classification of the reactor building zone and refuel zone ventilation dampers as continuously operating. The Team expressed a concern that these dampers receive a primary containment isolation signal, and thus their safety function is in standby. The licensee stated that during normal operation, these dampers are cycled open and/or closed on a weekly basis as part of a routine Operations procedure. The Team noted that non-risk significant SSCs in standby would require (reference NUMARC 93-01) monitoring at other than plant level. In addition, the Team's review of licensee PERs identified one instance involving a failure (to close) of dampers 2-64-13 and 2-64-14 in October 1995. This failure occurred during the weekly swapping of the reactor building zone ventilation supply

fans. The licensee entered an LCO for secondary containment which would require unit shutdown to begin after four hours. A few days later, a single Unit 1 damper failed upon receipt of a signal from the containment static pressure limiter. Initial corrective actions for each of the above failures included multiple cycling of the ASCO solenoid operated dampers. Additional corrective actions included replacement of all 24 reactor building zone ventilation supply and exhaust damper ASCO solenoids with a different ASCO solenoid model. The licensee has since experienced one failure of a single damper to close due to sticking solenoids (August 1996). The licensee's Maintenance Rule monitoring did not capture any of the above four component failures. However, the Team considered the licensee corrective actions for this issue to be appropriate to date.

The Team held discussions with the licensee regarding how the above failures were being captured by Maintenance Rule monitoring, and the classification of the dampers as continuously operating instead of standby. In response to the Team's concerns, the licensee held an Expert Panel meeting on April 17, 1997, and subsequently took the following actions. The licensee initiated a PER (BFPER970705) to document movement of the secondary containment to (a)(1). This was done to collect and evaluate data for revised performance criteria. This collection and evaluation was completed by the inspection end, and the function was returned to (a)(2) status. The licensee has also established specific performance criteria for the secondary containment function. This was done to provide a more suitable indicator of equipment performance, given the above failures. Changes to the Maintenance Rule program (0-TI-346) also were completed by the inspection end. The Team considered the licensee corrective actions for this concern to be thorough and complete.

Based on the risk significance of this issue, the existing weekly operation of the subject dampers, the licensee corrective actions of equipment failures for this isolated issue, and the reasonableness of licensee efforts to implement the Rule, the Team concluded that the licensee appropriately addressed the Team's concerns.

b.8 Condensate

The Condensate System condenses steam from the main turbine and delivers condensate water to the suction of the Feedwater System. The system also is used as a water source and heat sink to mitigate accidents and provide a makeup source to the RPV during emergency conditions. The system is safety-related and risk significant. Performance and monitoring criteria were established based on modified plant level criteria specific for the system. The criteria was based on number of scrams, number of unplanned capability loss (UCL) events, hours of UCL event unavailability, and number of failures of Condensate Transfer Pumps. The performance criteria is based on a rolling 24-month interval. The Team determined that these performance criteria coupled with the method of data collection employed by the licensee essentially provided monitoring of this system at the train level. The Team interviewed the system engineer, reviewed operator logs, Licensee Event Reports (LERs), PER logs, a sample of maintenance Work Order (WO) logs, and the Maintenance Rule Data Base to verify scrams, UCL Events, and UCL event unavailability were being captured in the data base and trended for re-classification

from (a)(2) to (a)(1) as appropriate. One Unit 3 scram, one Unit 3 UCL event, and one Unit 2 UCL event due to Condensate System component failures occurred over the last 24 months. None of the three events were caused by the same component. No Condensate Transfer Pump failures have occurred. Corrective action for all of these events was reviewed by the Team and were determined to be appropriate. The Team concluded that this system was properly classified as an (a)(2) system and was being properly monitored by the licensee.

b.9 Feedwater

The Feedwater System provides a flow path of feedwater into the reactor pressure vessel to maintain the water level within a predetermined range during all required modes of plant operation. The system is safety-related and risk significant. Performance and monitoring criteria was established based on modified plant level criteria specific for the system. The criteria was based on number of scrams, number of unplanned capability loss (UCL) events, and hours of UCL event unavailability. The performance criteria is based on a rolling 24-month interval. The Team determined that these performance criteria coupled with the method of data collection employed by the licensee essentially provided monitoring of this system at the train level. The Team interviewed the system engineer, reviewed operator logs, Licensee Event Reports (LERs), PER logs, a sample of maintenance Work Order (WO) logs, and the Maintenance Rule Data Base to verify scrams, UCL Events, and UCL event unavailability were being captured in the data base and trended for re-classification from (a)(2) to (a)(1) as appropriate. One Unit 3 scram, 1 Unit 3 UCL event, and one Unit 2 UCL event due to Feedwater System component failures occurred over the last 24 months. None of the three events were caused by the same component. Evaluation of these equipment failures did not result in exceeding the performance criteria or any changes to the performance criteria. Corrective action for all of these events was reviewed by the Team and were determined to be appropriate. The Team concluded that this system was properly classified as an (a)(2) system and was being properly monitored by the licensee.

c. Conclusions

Performance criteria were established, industry-wide operating experience was considered, where practical, appropriate trending was being performed, and corrective action was taken when SSCs failed to meet performance criteria, or when a SSC experienced a maintenance preventable functional failure for (a)(2) systems reviewed by the Team. An Inspector Followup Item was identified for further inspection of the Structures program after the licensee has completed more of the baseline condition walkdown inspections.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Material Condition Walkdowns

a. Inspection Scope (62706)

During the course of the reviews, the Team performed walkdowns of the following systems and plant areas, and observed the material condition of these SSCs.

- Unit 1 (1A and 1B) Shutdown Board Rooms and Associated HVAC System
- Bus Duct Cooling System
- Main Steam System
- Reactor Water Cleanup
- Reactor Building Zone and Refueling Zone HVAC
- Condensate System
- Feedwater System
- Emergency Diesel Generators
- EHC System
- Unit 3 inverters
- Unit 3 Emergency Diesel Generator Building

b. Observations and Findings

The Team performed material condition walkdowns on selected portions of each system that related to the areas inspected. Housekeeping in the general areas around system and components was acceptable. Piping and components were painted, and very few indications of corrosion, oil leaks, or water leaks were evident.

c. Conclusions

In general, the walkdowns determined that the systems were being adequately maintained.

M7 Quality Assurance In Maintenance Activities

M7.1 Licensee -Assessment

a. Inspection Scope (62706)

The Team reviewed licensee's audits to determine if Maintenance Rule self-assessments were conducted and the findings of the audits were addressed.

The Team reviewed four licensee audits:

- Nuclear Assurance and Licensing Assessment Report, (all TVA sites) Knowledgeable of the Maintenance Rule, L17 960703 800 dated July 3, 1996.

- Corporate Nuclear Assurance & Licensing Assessment Report (all TVA sites) Maintenance Rule Program, Report SSA9611 dated October 24, 1996 .

- Site Nuclear Assurance Vertical Slice of Performance Data for the Final Compliance Assessment of the BFN Maintenance Rule, dated March 24, 1996.

- Maintenance Rule -Assessment (conducted February 21 through 25, 1997), dated March 14, 1997.

b. Observations and Findings

The overall quality of the audits was good. Audits were detailed, addressed the Maintenance Rule, and a large number of recommendations were listed. The Team reviewed sufficient updated documentation that included the licensee's Maintenance Rule Program Manual, the Maintenance Rule Procedure 0-TI-346, and numerous PERs to verify that the recommendations and concerns in the audits were addressed. Licensee reviews also demonstrated a good knowledge of industry issues related to Maintenance Rule implementation. The licensee's assessment, dated March 14, 1997, was particularly thorough, and identified substantive issues related to overall implementation of the program at the corporate level, as well as items specific to Browns Ferry. The licensee stated that an additional assessment of the Browns Ferry Maintenance Rule program implementation is planned.

c. Conclusions

The Team concluded that audits and assessments were detailed and thorough. The concerns and recommendations were addressed in a timely manner. The licensee's assessment was considered to be particularly thorough, and implementation of recommendations assisted in correcting program weaknesses.

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 Team reviewed the applicable portions of the UFSAR that related to the areas inspected. The Team verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

E4 Engineering Staff Knowledge and Performance

E4.1 Engineer Knowledge of the Maintenance Rule

a. Inspection Scope (62706)

The Team interviewed licensee system owners (system engineers) for the SSCs reviewed in paragraphs M1.6 and M1.7 to assess their understanding of the Maintenance Rule and associated responsibilities.

b. Observations/Findings and Conclusions

The system engineers for those systems reviewed had considerable engineering experience and knowledgeable of their assigned systems and understood how to apply the rule to their systems. Additionally the system engineers had been proactive in corrective actions, and actively participated in Maintenance Rule development.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The team leader discussed the progress of the inspection with licensee representatives on a daily basis and presented the results to members of licensee management at the conclusion of the inspection on April 18, 1997. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

LICENSEE:

M. Bajestani, Plant Manager
G. Boles, Corporate Maintenance
C. Crane, Site VP
M. Cooper, Corporate Operations Support
R. Favreau, Corporate Maintenance
P. Heck, Maintenance Rule Coordinator
D. McCamy, Site Engineering (PRA Representative)
D. Nye, Site Support Manager
S. Schumitsch, Scheduling Manager
J. Sparks, Components Engineering Manager
G. Waldrep, Systems Engineering Manager
J. Wallace, Site Licensing
L. Williams, Site Engineering Manager

NRC:

B. Bearden, Reactor Inspector, RII
B. Crowley, Reactor Inspector, RII
S. Eide, NRC Contractor
R. Gibbs, Reactor Inspector, RII
B. Holland, Chief, Maintenance Branch, RII
J. Jaudon, Director, Division of Reactor Safety, RII
M. Miller, Reactor Inspector, RII
S. Sparks, Project Inspector, RII
D. Taylor, Operations Engineer, NRR
L. Wert, Senior Resident Inspector

LIST OF INSPECTION PROCEDURES USED

IP 62706	Maintenance Rule

LIST OF ITEMS OPENED

50-259/97-04-01	URI	Resolve Maintenance Rule Implementation on Browns Ferry Unit 1 (see section M1.1).
50-259,260,296/97-04-02	IFI	Review of Maintenance Rule Baseline Results for Structures (see section M1.7).

LIST OF ACRONYMS USED

BFNP	Browns Ferry Nuclear Plant
CIV	Containment Isolation Valve
CRD	Control Rod Drive

ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generators
EHC	Electro Hydraulic Control
EOP	Emergency Operating Procedure
FF	Functional Failure
HVAC	Heating Ventilation and Air Conditioning
IFI	Inspector Followup Item
IPE	Individual Plant Evaluation
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MPFF	Maintenance Preventable Functional Failure
MWE	Megawatts Electric
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
ORAM	Outage Risk Assessment Management
PER	Problem Evaluation Report
PM	Preventative Maintenance
PRA	Probabilistic Risk Assessment
QA	Quality Assurance
RHR	Residual Heat Removal
RO	Reactor Operator
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
SSC	Structures Systems and Components
SCR	Silicon Controlled Rectifiers
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSP	Site Standard Practice
TS	Technical Specifications
TVA	Tennessee Valley Authority
UCL	Unplanned Capacity Loss
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VAC	Volts Alternating Current

LIST OF PROCEDURES REVIEWED

Maintenance Rule 10 CFR 50.65 Program Manual, Rev. 2

Technical Instruction 0-TI-346, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Rev. 7

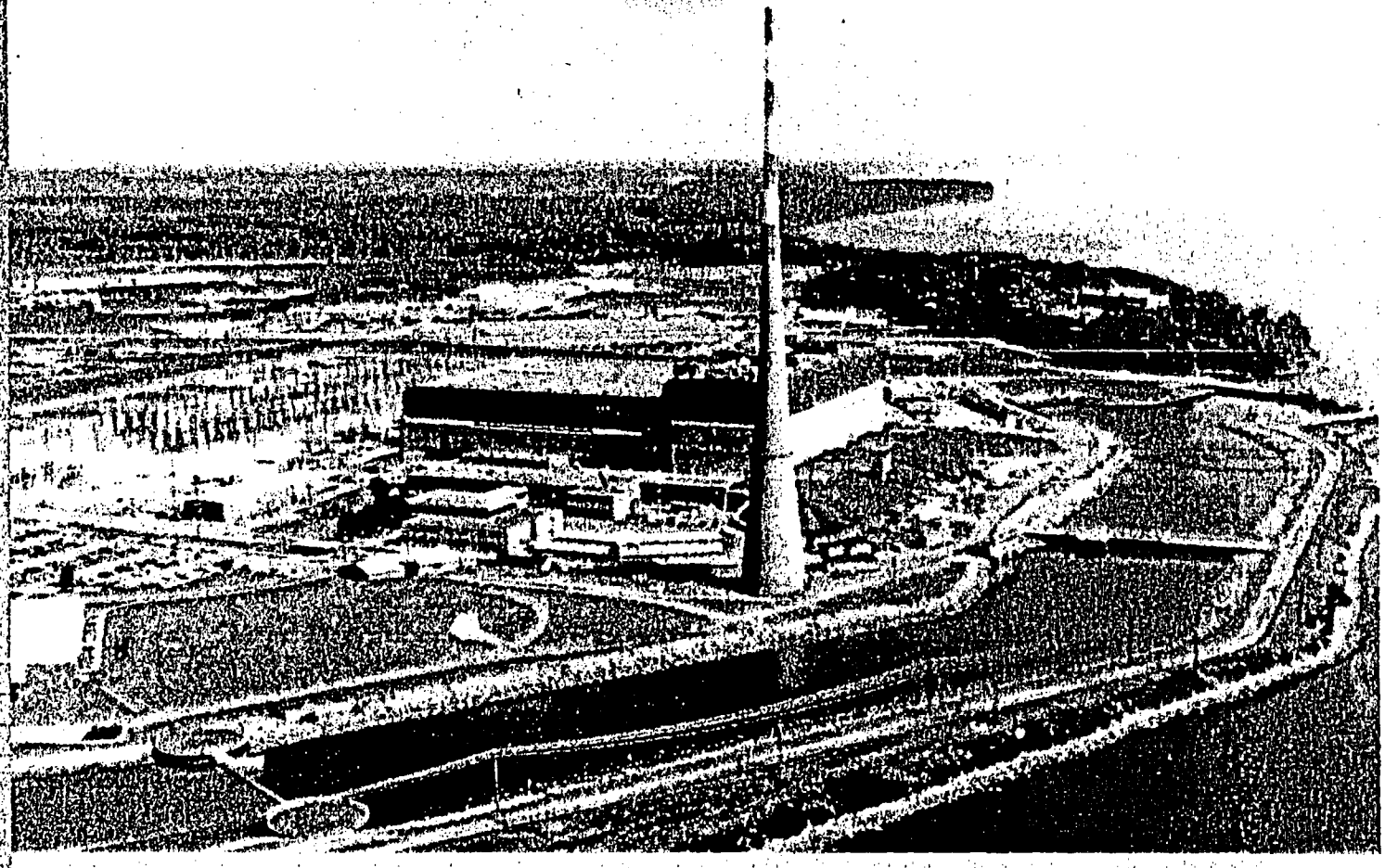
Site Standard Practice SSP-3.4, Corrective Action, Rev. 18

Site Standard Practice SSP-4.4, Managing the Operating Experience Program, Rev. 4

Site Standard Practice SSP-7.1, Work Control, Rev. 16

Site Standard Practice SPP-7.2, Outage Management, Rev. 0

Standard Engineering Procedure SEP-9.5.8, Probabilistic Safety Assessment (PSA) Program, Rev. 0



Browns Ferry Nuclear Plant

Maintenance Rule Presentation

April 1997

ENCLOSURE 2

Welcome

Chris Crane
Site Vice President

TVA

Agenda

- *Background*
- *The TVA Program*
- *Discussion of Program Bases*
- *Browns Ferry Implementation*
- *Organization*
- *Development*
- *Implementation*
- *Status*
- *Summary*

Introduction

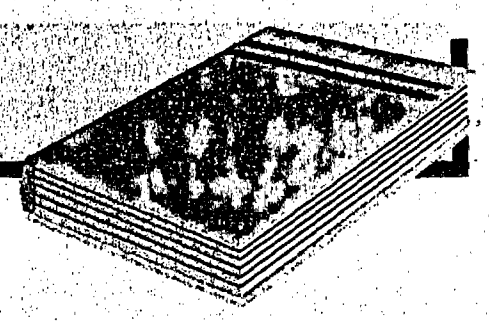
Gary Waldrep
Systems Engineering Manager

Mission Statement

TVA

To Develop a Maintenance Effectiveness Program That Satisfies the Requirements of 10CFR50.65. It Should Be Accomplished Through the Integration of Appropriate Site Equipment Reliability Processes With a Focus on Improving Plant Reliability. It Shall Be Commensurate With Safety While Reducing Overall Plant Costs.

The Program At TVA



John Sparks

Components Engineering

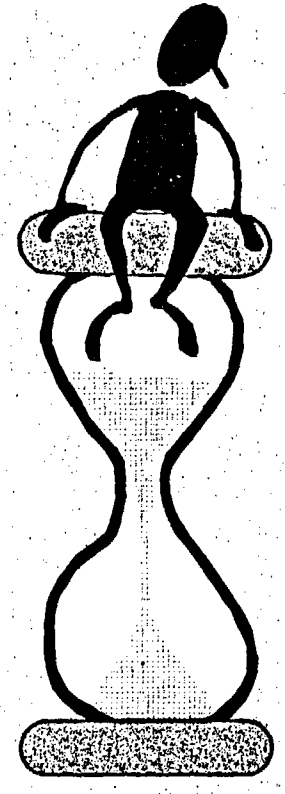
TVA
Program
Manual

BFN

SQN

WBN

Background



1991

- *Corporate Maintenance Rule Coordinator Established*
- *BFN Maintenance Rule Coordinator Established*
- *TVAN Peer Group Established*
- *Two TVAN Individuals on NUMARC Advisory Committee Drafting 93-01*

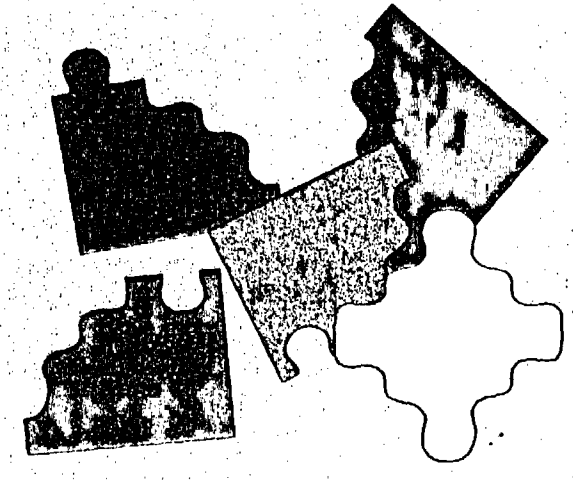
1992

- *NUMARC Assistance Visit*

Background (*continued*)

1993

- *NUMARC 93-01 Revision 0 Issued*
- *Industry Working Meetings Begin*
- *Industry Peer Visits*



1994

- *TVAN Program Manual Issued*
- *First Meeting of BFN Expert Panel*
- *First Meeting of BFN Steering Committee*
- *NEI Assist Visit*
- *Independent Contractor Review*
- *Performance Criteria Prepared*
- *Data Collection Begins*
- *Monitoring and Trending Begins*

Background (*continued*)

1995

- *NRC Issues NUREG 1526 - Results of Pilot Inspections*
- *BFN Maintenance Rule TI issued*

1996

- *Independent Assessments & Reviews*
- *Site Communication & Training Reinforce*
- *RULE Effective July 10, 1996*
- *Baseline NRC Inspections Results Review*
- *NEI Workshop - Industry Evaluation*
- *Ongoing Industry & NRC Communication*

KEY ELEMENTS

Program Manual

Incorporates 93-01 for Program Elements & Guidance

Unified TVAN Wide Program

Managed by Corporate Maintenance Rule Coordinator

Expert Panel (during development phase)

Chaired by BFN Maintenance Rule Coordinator

Key Representation - Engineering (PSA), OPS, Maintenance

Approved Scoping, Risk Significance, & PC

Steering Committee (during development phase)

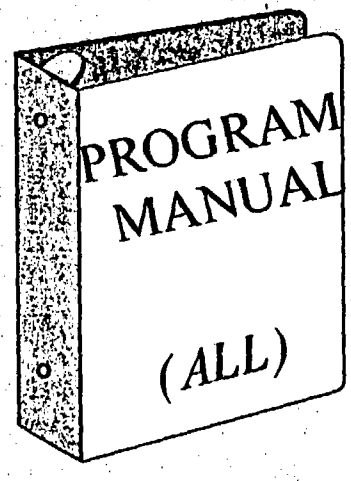
Chaired by Plant Manager

Corporate Maintenance Coordinator Advisor

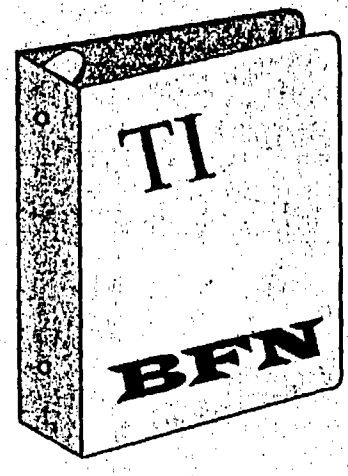
Key Representation - Engineering, OPS, Maintenance

Management Strategy, Oversight, TVAN Consistency

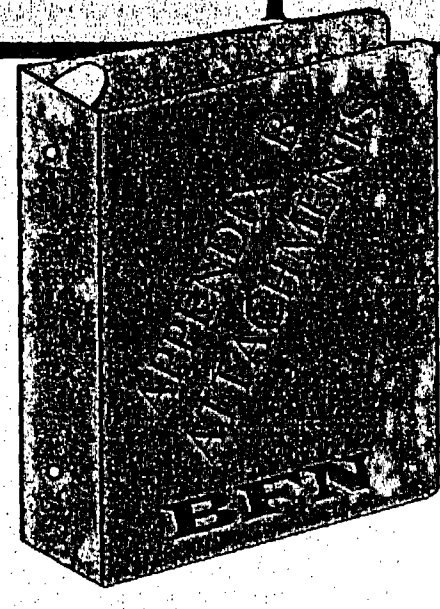
The Program Concept



ONE MANUAL FOR ALL SITES

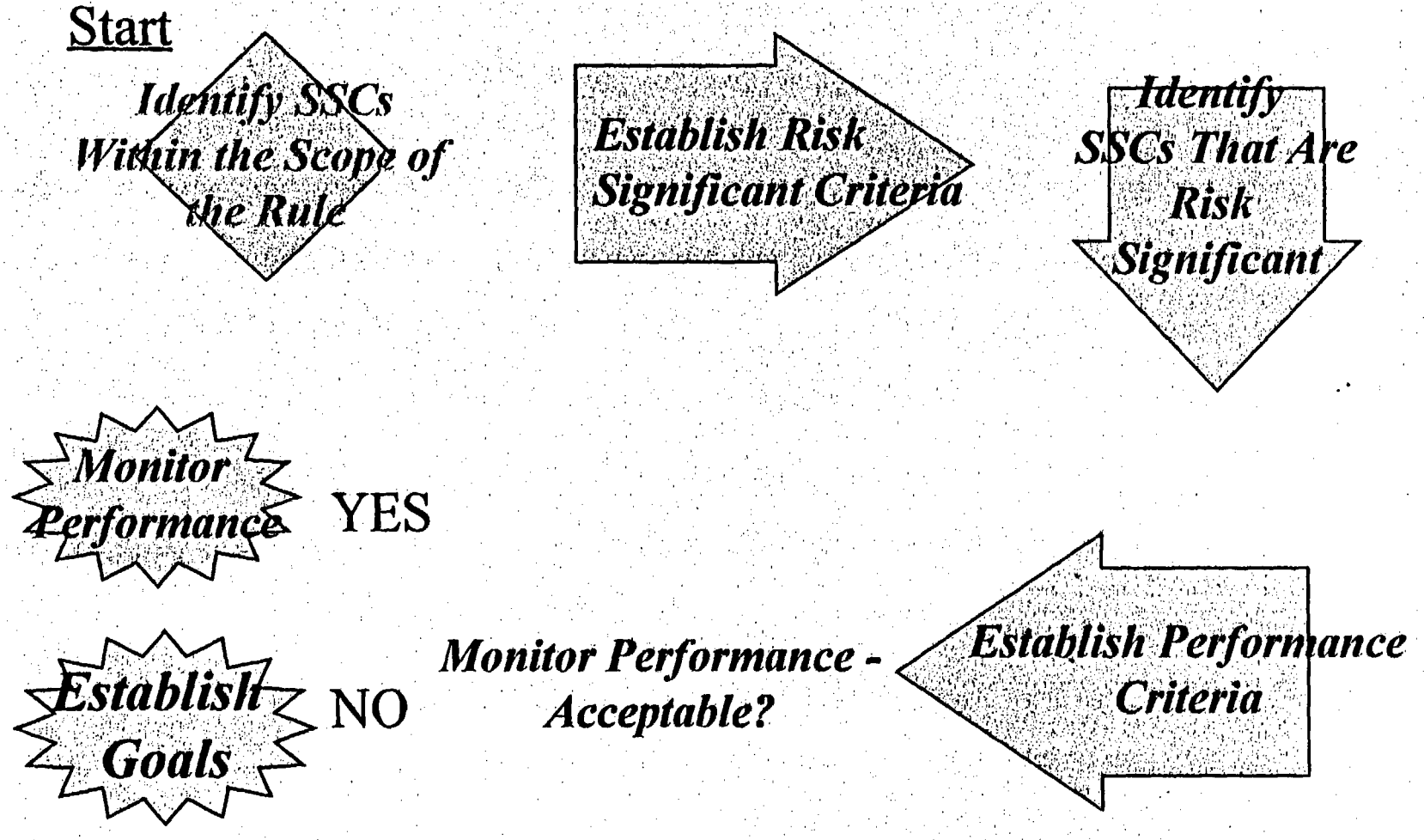


EACH SITE HAS SAME BASIC TI



UNIQUE APPENDIX & ATTACHMENTS FOR EACH SITE

The Basic 10CFR50.65 Process



50.65 (b)Scoping

- UTILIZED 93-01 GUIDANCE
- SECTION 3.4.1 TVA PROGRAM MANUAL
- SPECIFIC LISTING FOR BFN - GIVEN IN TI APPENDIX B
- INITIAL LIST COMPILED BY SITE EXPERT PANEL
- PROGRAM IS DYNAMIC :
  - *DESIGN CHANGES*
  - *OPERATING EXPERIENCE*
  - *PSA UPDATES*
  - *PLANT PROCEDURE REVISIONS*
  - *INDUSTRY LESSONS LEARNED*

SCOPE CHANGES

Determine Risk Significance

- Performed at the System Level
- Bases from IPE GL-88-20
  - *Results Documented in Site IPE*
  - *DELPHI From Expert Panel*
- Established by Expert Panel
- TVA Program Manual Identifies Methodology (Para 3.4.2)
- BFN TI, Appendix B Provides Listing
- Will Change as the PSA Model Changes Over Time

Implementation Elements

- **10 CFR 50.65 (a)(2) PC & Monitoring**
  - ***System Level Specific & Plant Level***
  - ***CDEFs/FF/PFF/RPFF***
- **10 CFR 50.65 (a)(1) Goal Setting & Monitoring**
  - ***Criteria for (a)(1)***
  - ***Root Cause, C/As, Goals***
  - ***Performance to Return to (a)(2)***
- **10 CFR 50.65 (a)(3)**
  - ***Balancing Availability & Reliability***
  - ***Assessment of Risk for Removal of SSCs from Service***
  - ***Periodic Assessment of Maintenance Effectiveness***

The Browns Ferry Program

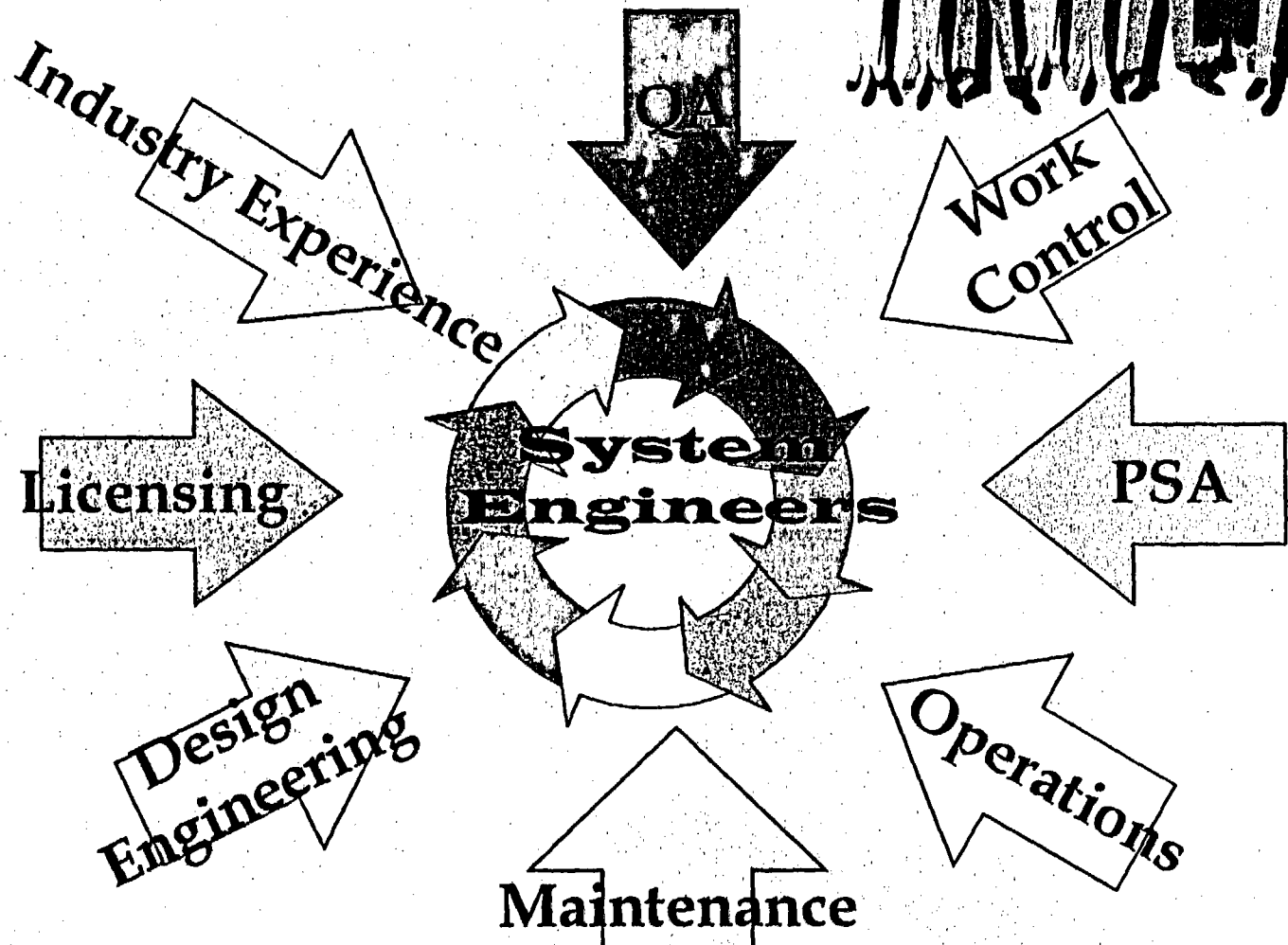
Paul Heck
Maintenance Rule Coordinator

TVA

TVA BFN Program Bases

- Meets 10CFR50.65
- Follows the Guidance of Regulatory Guide 1.160 "Maintenance Program Implementation"
- Follows the Guidance of NUMARC 93-01
- Consistent with NRC Maintenance Rule Inspection Program (NRC IP 62706 & 62707)

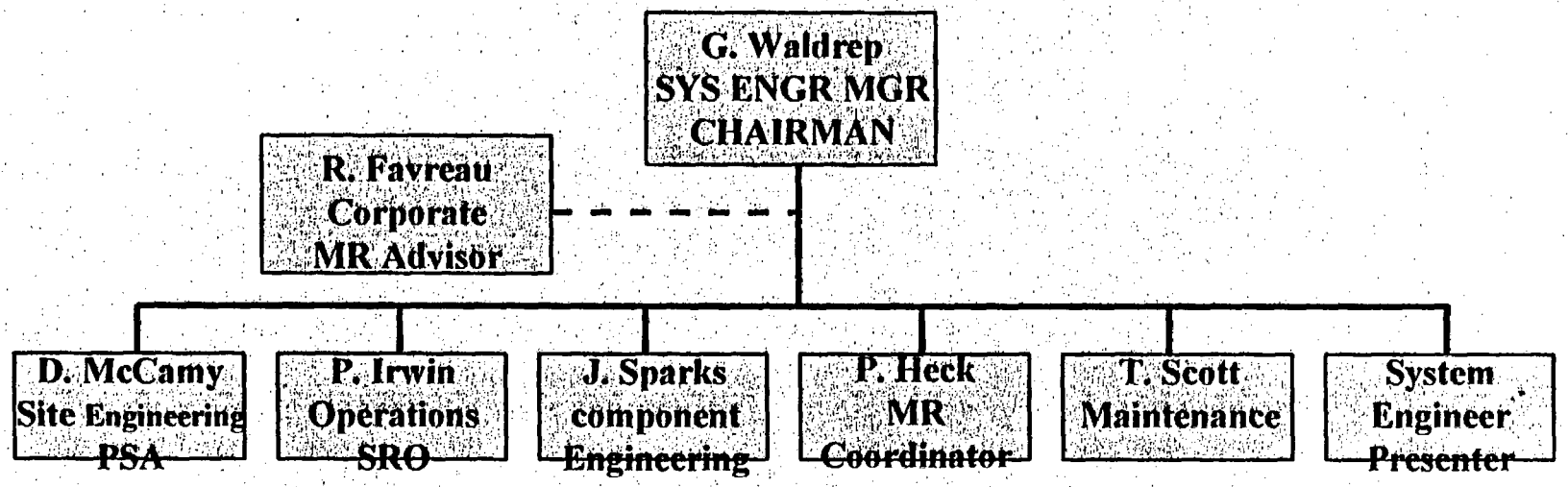
Involvement at Browns Ferry



Related Procedures

- Corrective Action SSP-3.4
- Operating Experience SSP-4.4
- EOPs SSP-12.16
- Work Control SSP-7.1
- Outage Management SPP-7.2
- Design Change Control SSP-9.3
- LCEI BFEP-CI-C9 Structural Walkdown
- PSA Program SEP-9.5.8

Expert Panel*

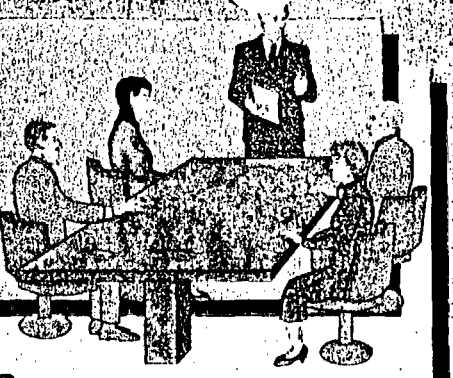


***Charter: 0-TI-346**

Risk Significance & the Expert Panel

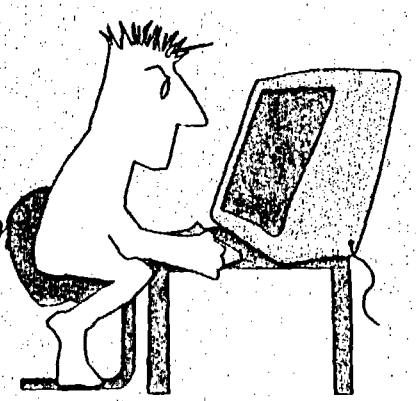
- Identified Systems That Support Critical Safety Functions (Such As Described in FSAR, Design Documents)
- Made Risk Significance Decisions Based on Expertise
- Integrated PSA Results With Deterministic Input

Expert Panel Responsibilities



- Experience from Ops, Engineering, PSA & Maintenance
- Advise Site Senior Management Concerning SSCs Performance Relative to 50.65
- Review Changes to Scoping & Risk Significance
- Review Adequacy of Performance Criteria (As Required)
- Approve SSCs for Movement From (a)(2) to (a)(1)
- Approve SSCs for Movement From (a)(1) to (a)(2)
- Review Periodic Assessments

Tools to Implement 10CFR50.65



- **PLANT PROCESS COMPUTER**
- **NOMS (LCOs, Ops Logs, Hold Orders)**
  - ***Nuclear Operations Management System***
- **EMPAC (Work Orders)**
  - ***Enterprise Maintenance Planning and Control***
- **TROI (PERs Data)**
  - ***Tracking and Reporting of Open Items***
- **Maintenance Rule Database**
- **System Status (Health) Report**
- **BFN MR Information Line - Dial 7600**

10CFR50.65(a)(2) Monitoring

Methodology Defined in TVA Program Manual Sec. 3.4.3

PLANT LEVEL
(SCRAMS, SSA, UCLF)
BUSINESS & WORK PERF. GROUP

TI SECT. 7.2

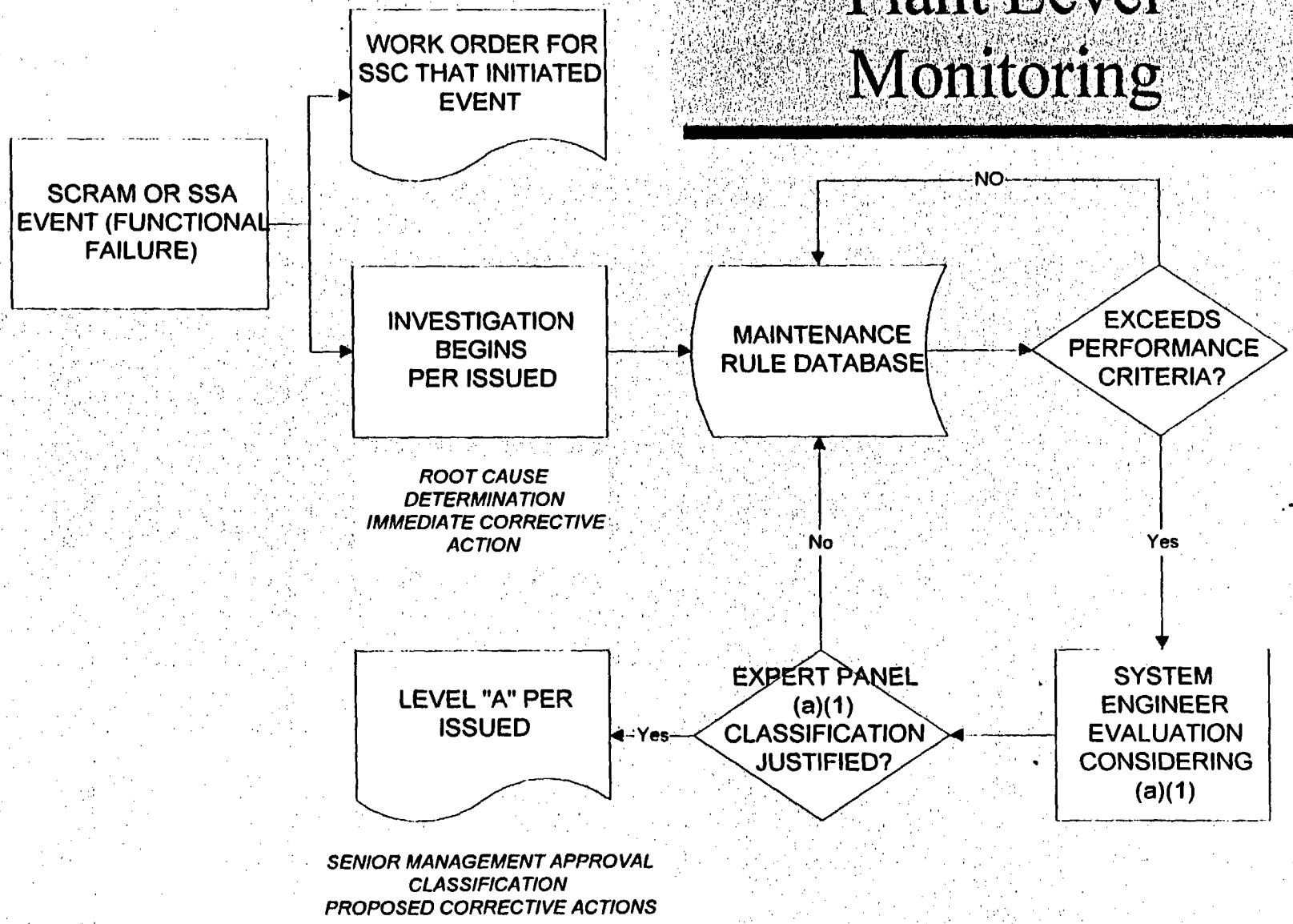
MAINTENANCE RULE DATABASE

BFN 0-TI-346

SPECIFIC LEVEL
SYSTEMS ENGINEERING

TI SECT. 7.3

Plant Level Monitoring

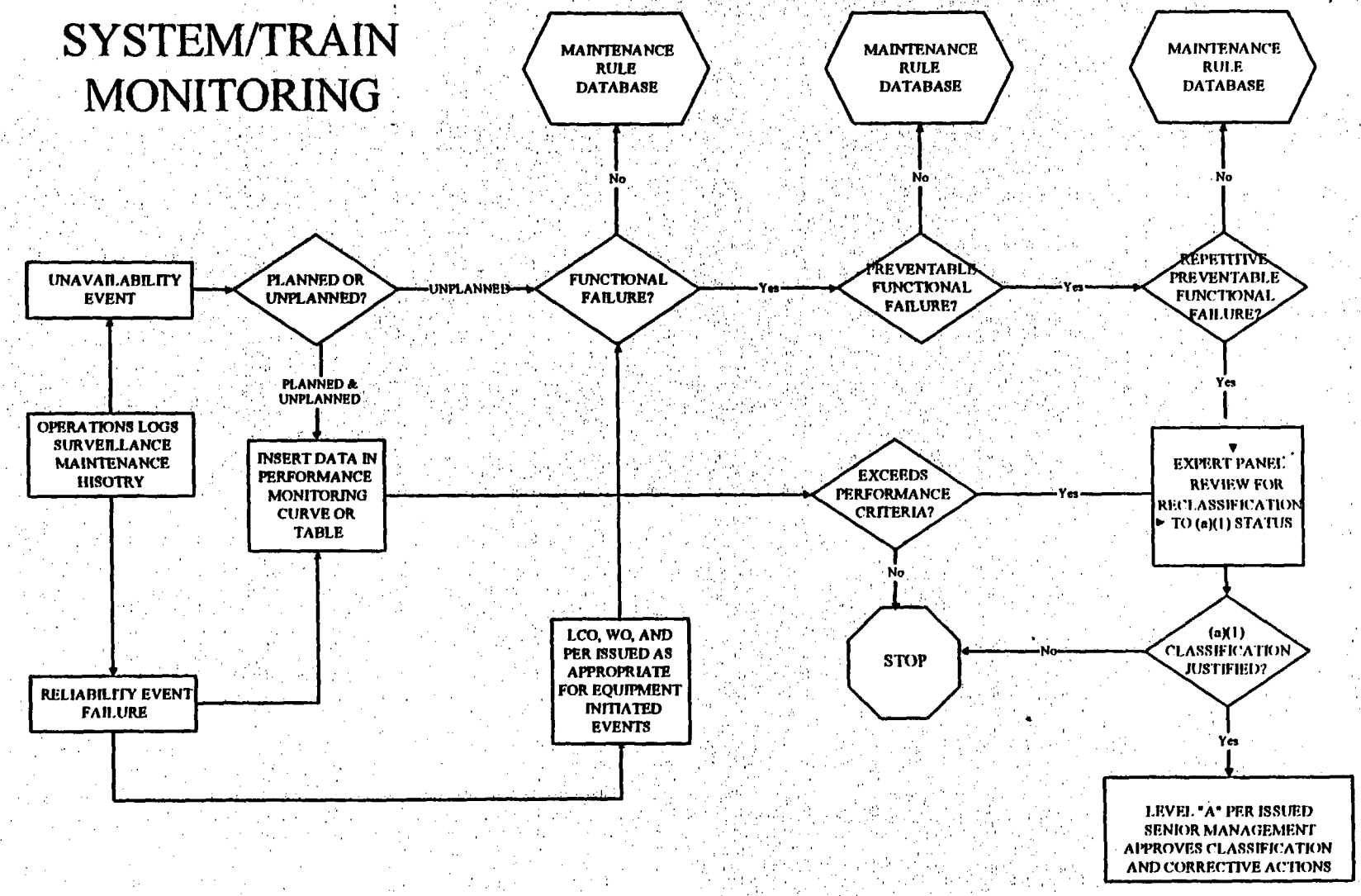


(a)(2) Plant Level Performance Criteria

Plant Level Performance Criteria - TI Section 7.2

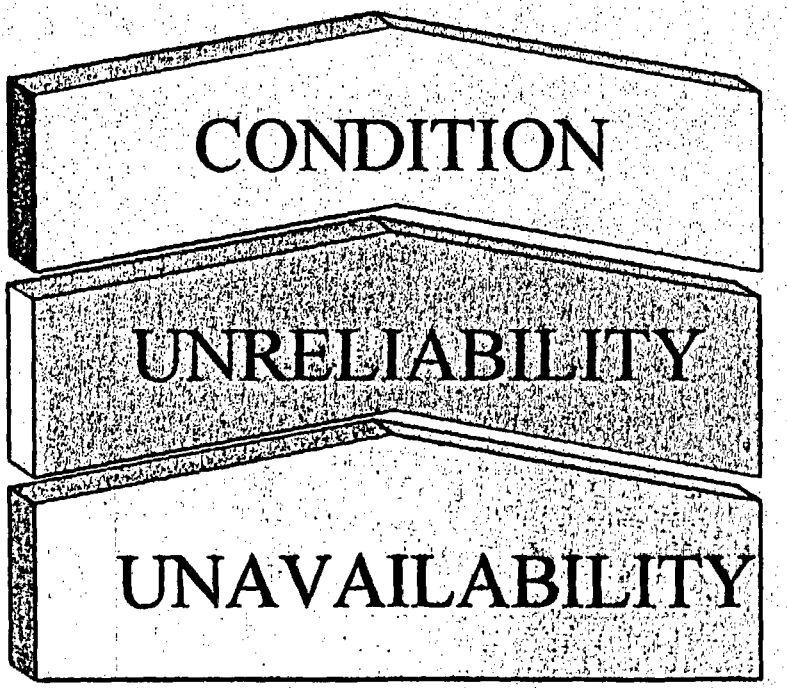
- **SCRAMs - no more than 2 per system per unit or no more than 4 per unit total (last 24 months)**
- **UCLF - no more than 4.3% per unit or no more than 2.2% or 3 UCL events per system (last 24 months)**
- **SS Actuations - no more than 2 per system per unit or no more than 4 per unit total (last 24 months)**

System - Train Monitoring



(a)(2) Specific Performance Criteria

TI Section 7.3 & Attachments



Monitoring Examples

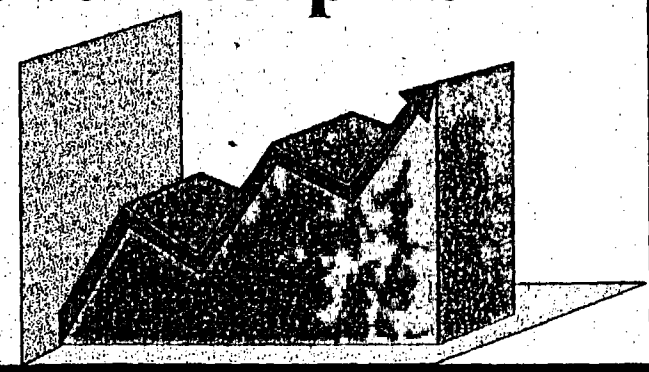
- ***SCRAMs*** - U2, 10/29/96, Sys 242, Main Generator - Exciter brush problem resulted in reactor scram from full power. Problem determined to an inadequate PM instruction which provided incorrect guidance on exciter brush replacement. Reference BFPER961466.

- ***Functional Failure*** - U2, 6/7/95, Sys 73, HPCI - Steam supply valve 2-FCV-073-0016 failed to open on manual initiation. The problem was determined to be arc strikes on the motor starter contacts due to age and use. Reference BFPER BFPER950690.

- ***ESF Actuation*** - U2, 1/21/96, Sys 82, Diesel Generators -Unit 1/2 'B' EDG auto-started during a routine local panel test. A failed diode caused a diesel auto start when an AUO placed a test jumper to perform a trouble alarm check. Reference BFPER960042.

50.65(a)(1)

- Process Defined By TVA Program Manual Section 3.4.3.D
- Implementation - BFN TI Sections 8.0 & 9.0
- Purpose - To Return SSC's to Acceptable Performance



(a)(1) 9 Point criteria

- SSC Function ID
- Performance Monitoring Factors
- Direct Cause
- Analyze Unavailability & Reliability
- Corrective Actions
- Industry Experience Sources
- Interim Performance Monitoring Indicators
- Level of Performance to Return to (a)(2)
- Monitoring Schedule

BFN Systems in (a)(1) Category "Goal Setting" as of March 1997

- U2 System 001, Main Steam SRV's
- U3 System 001, Main Steam SRV's
- U2 System 064A, Primary Containment Integrity (3 specific valves for LLRT issues)
- U3 System 256, ECCS ATU Inverters

Structural Program
July 96 Implementation

TVA

0-TI-346 Attachment 38

- ***Scope, Function, and Description***
- ***Performance Criteria***
- ***Monitoring and Trending***

BFEP-CI-C9 Walkdown of Structures

- ***Responsibilities and Personnel Qualifications***
- ***Inspection Guidelines and Checklists***

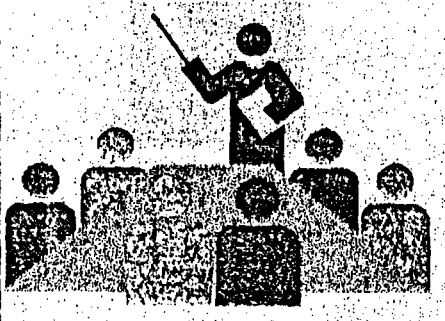
Baseline Walkdown In-Process

- ***100% no later than December 31, 1998***

(a)(3) Assess Impact of Maintenance on Plant Safety

- **Work Control SSP-7.1**
- **Work Week Managers**
- **Manage 12 Week Schedule**
  - ***Per Risk Matrix (SSP-7.1)***
- **Integrated With Surveillance Program**
- **Outage Management SPP-7.2**

Site VP Defined Training



- MAINTENANCE & MODS
- OPERATIONS
- SCHEDULING
- ENGINEERING (INCLUDES SYSTEMS, STRUCTURAL & PSA)
- RADCON & CHEM
- OUTAGE MANAGEMENT
- LICENSING
- BUSINESS & WORK PERFORMANCE
- SITE SUPPORT

Summary

TVA

- **Program Implements** 10CFR50.65 **requirements**
  - ***Includes Industry Guidance Documents***
  - ***Active Participation in Industry Initiatives***
- **Developed** Procedures
  - ***Integrated With Existing Programs***
- **Provided** Training
- Implemented Program 7/10/96
- Active Involvement in the Lessons Learned process
- Continue with Program Enhancements as Experience Dictates