U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-334 and 50-412
License Nos:	DPR-66 and NPF-73
Report Nos:	50-334/97-80 and 50-412/97-80
Licensee:	Duquesne Light Company Post Office Box 4 Shippingport, PA 15077
Facility Name:	Beaver Valley Power Station (BVPS), Units 1 & 2
Dates:	July 7-11, 1997
Inspectors:	J. Williams, Senior Operations Engineer, Team Leader T. Fish, Operations Engineer J. Trapp, Senior Reactor Analyst G. Dentel, Resident Inspector F. Talbot, Operations Engineer, HQMB, NRR W. Scott, Senior Operations Engineer, HQMB, NRR Dr. S. Wong, NRC Contractor
Approved by:	Glenn W. Meyer, Chief Operator Licensing and Human Performance Branch Division of Reactor Safety

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This inspection reviewed Beaver Valley's implementation of 10 CFR 50.65, the maintenance rule. The report covers a 1-week onsite inspection by regional and NRR inspectors during the week of July 7, 1997.

MAINTENANCE

- The team concluded that DLC had done a very good job in scoping SSCs into the maintenance rule.
- The level of detail provided in the PRA's truncation limits and quality were appropriate to perform risk categorization in accordance with the rule.
- The risk ranking methodology was consistent with industry guidance and the basis for risk ranking decisions were thoroughly documented.
- The composition of the expert panel was appropriate. The responsibilities of the expert panel were detailed in administrative procedures.
- The performance criteria for risk significant SSCs were appropriate and a link to the PRA assumptions was appropriately established. In a few cases, the team noted that the performance criteria for non-risk significant standby SSCs did not appear to be linked to historic performance or expected performance.
- A number of SSCs were reviewed in detail by the team. The team concluded that the six (a)(1) and thirteen (a)(2) SSCs reviewed met the requirements of the rule. The team found the goals for the (a)(1) SSCs and the corrective actions taken were acceptable.
- The structures monitoring program at the Beaver Valley Power Station (BVPS) was considered strong by the team, and had been used to categorize one structure as (a)(1).
- The PRA group was involved in conducting safety assessments when taking equipment out of service for on-line maintenance, and these assessments were very good.
- The team concluded that the periodic assessment reflected a self-critical and thorough approach, and it met the requirements of paragraph (a)(3) of the rule.
- The recent QA audit of the maintenance rule program was thorough and the DLC response to the findings appeared to be appropriate.
- System engineers and senior reactor operators had good overall knowledge of the maintenance rule.

Report Details

M1 Conduct of Maintenance (62706)

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

a. Inspection Scope

The team reviewed the scoping documentation to determine if the appropriate structures, systems and components (SSCs) were included within the maintenance rule program in accordance with 10 CFR 50.65(b). The team used NRC Inspection Procedure (IP) 62706, NUMARC 93-01, Regulatory Guide (RG) 1.160, the BVPS Updated Final Safety Analysis Report (UFSAR), the Master Equipment List (MEL), the Emergency Operating Procedures (EOPs), the Abnormal Operating Procedures (AOPs) and other information provided by DLC as references. The references included System and Performance Engineering Administrative Procedure (SPEAP) 3.2, "Maintenance Rule Program Administration," Revision 2, dated June 20, 1997, and maintenance rule system basis documents.

b. Observations and Findings

SPEAP 3.2 identified the methodology for selecting SSCs that should be included within the scope of rule. DLC identified 66 SSCs for Unit 1, 70 SSCs for Unit 2 and eight SSCs shared between both units that were under the scope of the maintenance rule. DLC also identified 33 SSCs for Unit 1 and 27 SSCs for Unit 2 that were excluded from the scope of the rule. The system basis documents identified system boundaries and functions included within the scope of the maintenance rule for each system. The team used these documents to verify DLC's scoping decisions.

The team reviewed additional information on scoping decisions for the following SSCs: cooling towers; turbine buildings; emergency response facility (ERF) safety parameter display system (SPDS); turbine generator subsystems; plant process computer system; discharge structure; circulating water pump house; site grounding system; gaseous waste disposal system for Unit 2; and some reactor coolant system instrumentation (i.e., reactor vessel level instrumentation system and in-core thermocouples).

DLC provided the team with additional information on scoping decisions for all the SSCs mentioned above. The team found that the reactor coolant instrumentation and turbine generator subsystems were included in scope. After discussions with the team, DLC added the cooling tower hyperbolic structure to the scope of the maintenance rule. The team found that DLC had established adequate technical justification to exclude the remaining SSCs from the scope of the maintenance rule.

c. Conclusions

The team concluded that DLC had done a very good job on scoping, and based on the sample of SSCs reviewed, SSCs were properly included within the scope of the maintenance rule.

M1.2 Safety (Risk) Determination, Risk Ranking, and Expert Panel (62706)

a. Inspection Scope

Paragraph (a)(1) of the maintenance rule requires that goals be established commensurate with the safety significance of the SSC. Implementation of the rule, using the guidance contained in NUMARC 93-01, requires that safety be taken into account when setting performance criteria and monitoring under (a)(2) of the rule. This safety consideration should be used to determine if the SSCs would be monitored at the system, train, or plant level. The team assessed the process for determining the safety significance of SSCs included in the scope of the maintenance rule. The team also verified that the expert panel had properly determined the safety significance and established appropriate performance criteria for several SSCs.

b. Observations and Findings on Safety (Risk) Determinations, Risk Ranking, and Expert Panel

Safety Determinations and Rankings

An expert panel determined the safety significance of SSCs included within the scope of the maintenance rule. The expert panel members used information derived from the probabilistic risk assessment (PRA) to assist in the decision making. This information was system importance measures from the PRA related to both core damage and containment failure. The plant-specific PRA importance measures were used to rank SSCs with regard to risk significance.

The RISKMAN software was used in the full quantification of the PRA models for calculating SSC risk significance ranking measures. The information used in risk ranking Unit 1 SSCs was based on a PRA model developed to support the 1995 external event PRA study (IPEEE). The IPEEE PRA model was an update of the original individual plant examination (IPE) to include the electrical power cross-tie from Unit 2 and improved model of primary pressure relief capacity for anticipated transient without scram sequences. The risk ranking of Unit 2 SSCs was based on the 1992 PRA model developed for the IPE. The team noted that the DLC had developed a process to revise the maintenance rule program following PRA enhancements.

The initiating event frequencies were updated in the PRA models to reflect plant operating experience. Generic failure data for component failures and unavailabilities were used in the PRA calculations. Plant-specific data was used when statistically sufficient data was available. A Bayesian updating process was used to aggregate generic and plant-specific data in several cases. The PRA database of basic event failure rates and unavailabilities for the Units 1 and 2 PRA models were last updated in 1995 and 1992, respectively.

The team determined that the truncation limit was appropriate for the risk ranking process. A truncation level of 1E-9 was used to quantify the PRA results used for risk ranking. This truncation level was five orders of magnitude less than the overall core damage frequency (CDF) estimated for Unit 1 (1.2E-4 per reactor year) and Unit 2 (1.9E-4 per reactor year). The BVPS PRA staff stated that a truncation level of 1E-10 was used in some risk sensitivity calculations when a larger number of sequence cutsets was needed.

The quantitative measures used to assess system safety significance were risk achievement worth (RAW), Fussell-Vesely (FV) importance, and cutsets which cumulatively contribute to 90 percent of the calculated CDF. The risk metrics used for calculating the importance measures reflected information on both containment and core performance. The selection criteria and risk metrics selected were consistent with the NUMARC 93-01 guidance for maintenance rule implementation.

The team reviewed a sample of SSCs within the scope of the rule to verify that the expert panel had properly determined the safety significance of selected SSCs. In general, the team found that the expert panel had properly categorized the safety significance of SSCs and had thoroughly documented the basis for their conclusions. However, in two cases, the team concluded that the bases for categorizing the Unit 1 dedicated feedwater pump (DFP) and the recirculation spray system (RSS) sumps (Units 1 & 2) as non-risk significant were not thoroughly documented or technically sound. The expert panel addressed the team's concerns and subsequently recategorized these SSCs in an acceptable manner.

Specifically, the FV importance measure for the DFP exceeded the NUMARC cut-off value (>0.5%) for risk significance. The maintenance rule system basis document stated that the DFP was determined by the expert panel to be non-risk significant because the criterion value for the other two risk importance measures were not exceeded. The team noted that exceeding one importance metric is sufficient to identify a safety significance SSC. Therefore, the bases for determining that this system was non-risk significant was not technically sound.

The expert panel determined that the RSS, with the exception of the RSS sump, was risk significant. The team noted that the RAW for the RSS sump exceeded the NUMARC guidance cut-off value (>2.0) for risk significance. The maintenance rule system basis document stated that the RSS sump was determined by the expert panel to be non-risk significant because the sump was a passive, highly reliable component that was routinely inspected. The team questioned the basis for concluding that sumps are highly reliable. Industry experience has documented several instances of containment sump performance degradation at other facilities. In addition, the statement that the sumps are passive and reliable are not alone a sufficient basis to conclude that a SSC is non-risk significant. The maintenance rule coordinator (MRC) stated that based on the team's comments, the risk significance for these SSCs would be re-evaluated at a future expert panel meeting.

The expert panel met on July 16,1997, to consider the team's issues on risk ranking and performance criteria. The team reviewed the minutes of this expert panel meeting. The panel concluded that it was appropriate to include the sump as part of the containment system (a risk significant system). In addition, the performance criteria for the sump was revised to account for the critical function of the Unit 1 quench spray system. The panel concluded that the Unit 1 dedicated auxiliary feedwater pump was non-risk significant, but recommended that reliability performance criteria be developed for the pump. The team determined that DLC had adequately addressed the issues associated with the dedicated feedwater pump and the recirculation spray system sumps.

Expert Panel

The team interviewed several expert panel members, reviewed the expert panel meeting minutes, and observed an expert panel meeting. The expert panel membership included representatives from operations, maintenance, design engineering, systems and performance engineering, nuclear safety, and the PRA group. The total experience of the expert panel members was over 150 man-years of nuclear industry experience. The team noted that the expert panel members who did not have a strong PRA background had received some PRA training. The administrative procedures defined the responsibilities of the expert panel to include identifying the SSCs that are within the program scope, determining the risk significance and performance criteria for SSCs, and setting goals for SSCs that exceed the performance criteria. The administrative procedures requirements describing the responsibilities of the expert panel were consistent with the NUMARC 93-01 guidance. The expert panel meetings minutes were detailed. The conduct of the expert panel meeting complied with administrative procedure guidance.

c. Conclusions on Safety (Risk) Determinations, Safety (Risk) Ranking, and Expert Panel

The team concluded that the level of detail provided in the PRAs, truncation limits and quality were appropriate to perform risk categorization in accordance with the maintenance rule. The risk ranking methodology was consistent with industry guidance and the basis for risk ranking decisions were, in general, thoroughly documented. With one exception, the risk ranking decisions, in general, were made appropriately. After further discussions and review of the expert panel meeting minutes of July 16, 1997, the team had no issues or concerns with the risk ranking decisions. The composition of the expert panel was appropriate and the responsibilities of the expert panel were detailed in administrative procedures.

M1.3 Goal Setting and Monitoring (a)(1) and Preventive Maintenance (a)(2) (IP 62706)

a. Inspection Scope

The team reviewed program documents in order to evaluate the process established to set goals and monitor under (a)(1) and to verify that preventive maintenance had been demonstrated to be effective for SSCs under (a)(2) of the maintenance rule. The team discussed the program with appropriate plant personnel. The team also verified that appropriate performance criteria had been set for several SSCs. The team performed detailed programmatic reviews of maintenance rule implementation for the following SSCs for both units:

- Reactor Coolant System/Reactor Coolant Pumps- (a)(1) for Unit 1 and (a)(2) for Unit 2
- Containment Depressurization/Quench Spray- (a)(2) for both units
- Feedwater System- (a)(2) for both units
- Auxiliary Feedwater System- (a)(1) for Unit 2 and (a)(2) for Unit 1
- River/Service Water System- (a)(1) for both units
- Compressed Air System- (a)(2) for both units
- Emergency Diesel Generators and Support Systems- (a)(2) for both units
- Containment System- (a)(2) for both units
- Switchyard- (a)(1) common to both units
- Structures- (a)(1) for the safeguards building for Unit 2 and (a)(2) for all other structures

The team reviewed each of these systems to verify that goals or performance criteria were established in accordance with safety, that industry-wide operation experience was taken into consideration, that appropriate monitoring and trending were being performed, and that corrective actions were taken when a SSC failed to meet its goal or performance criteria or experienced a maintenance preventable functional failure (MPFF). The team also reviewed goals and performance criteria for SSCs not listed above.

b. Observations and Findings

Goal Setting and Performance Criteria

The team reviewed the performance criteria to determine if the DLC had adequately established performance criteria under (a)(2) of the maintenance rule. The administrative guidance for establishing performance criteria was outlined in Administrative Procedures NPDAP 8.30, "Maintenance Rule Program," and SPEAP 3.2, "Maintenance Rule Administration." The administrative guidance included the use of a PRA process in developing the reliability and unavailability performance criteria for risk significant SSCs.

The team noted that the unavailability criteria of risk significant SSCs were correlated and in some cases, more stringent than the unavailability assumptions used in the PRA. The DLC had evaluated the change in CDF due to the unavailability criterion for each of the risk significant SSCs such that CDF increase did not exceed 5 percent. The DLC PRA staff performed a PRA sensitivity analyses to evaluate the cumulative risk impact of setting the unavailability criteria equal to the unavailability performance criteria for all risk significant SSCs. The sensitivity analyses results showed a small increase in CDF. The sensitivity analysis used a revised PRA that included an improved modeling of the direct current (dc) power system. The DLC PRA engineers stated that a new PRA model which credits de-pressurization of reactor coolant system in the event that all high pressure injection were to fail during a small break loss of coolant accident would result in a decrease in overall CDF to the mid 1E-5 range.

DLC determined a maximum number of maintenance preventable functional failures (MPFFs) over a 36-month period for monitoring the reliability of all risk significant SSCs. The reliability performance criteria vary from 0 to 3 MPFFs per three-year period depending on the PRA unreliability values (if the SSC was modeled in the PRA), the estimated number of demands during the three-year period, and other industry reliability data information. The team found that the reliability performance criteria were properly correlated to the PRA equipment reliability data with one isolated exception. The team determined that the reliability performance criteria for the Unit 1 quench spray pumps was not appropriately linked to the equipment reliability used in the PRA. On the basis of the PRA assumed value for reliability, the team concluded that 0 MPFF would have been an appropriate performance criteria for the failure of this pump to start. BVPS had established one or more MPFF as the performance criteria for these pumps. The MRC stated that the performance criteria for the Unit 1 quench spray pumps would be re-evaluated by the expert panel. The DLC approach for establishing the reliability performance criteria was based on using the appropriate statistical distributions (e.g., binomial distribution for standby SSCs and Poisson distribution for operating SSCs) to calculate SSC train failure probabilities. The methodology used to link the reliability performance criteria to the PRA for risk significant SSCs was good.

The reliability performance criteria for non-risk significant standby SSCs varied between 0 and 3 MPFFs. The maintenance rule administrative procedures did not provide detailed guidance on establishing MPFF criteria for non-risk significant standby SSCs. In a few cases, the MPFFs for non-risk significant standby SSCs did not appear to be appropriately linked to historic performance but the expert panel addressed these concerns. For example, the reliability performance criteria for the RSS sump was less than 2 MPFF in a 3 year period. The team determined that setting the reliability performance criteria of 2 MPFFs per train was too high for a reliable system like the RSS sump and was unlikely to move the RSS sump to (a)(1) if poor performance was experienced. The MRC stated that this issue would be reviewed by the expert panel. The panel reviewed this issue at its July 16, 1997, meeting and revised the performance criteria to apply on a system verses train level. The team found this to be acceptable.

Detailed Review of (a)(1) and (a)(2) SSCs

The team reviewed the implementation of the maintenance rule for individual (a)(1) and (a)(2) systems for Units 1 and 2. The team reviewed each of the six (a)(1) and thirteen (a)(2) SSCs to verify that goals or performance criteria were established in accordance with safety, industry wide operating experience was taken into consideration, and appropriate monitoring and trending were being performed. The team found acceptable the goals for the (a)(1) SSCs and the corrective actions taken when an SSC failed to meet its goal or performance criteria or experienced an MPFF.

The team reviewed several MPFFs evaluations and (a)(1) to (a)(2) evaluations. The system engineers performed the MPFF evaluations with assistance from the MRC's staff. The MPFF evaluations reviewed were completed correctly with proper justifications. Based on exceeding MPFF limits, the Unit 1 compressed air system was categorized (a)(1) in May 1996. The system was moved from (a)(1) to (a)(2) in February 1997. The maintenance rule program procedures had a clearly defined method for dispositioning SSCs from (a)(1) to (a)(2). The compressed air system met its goals and performance criteria for three successive surveillance intervals and was properly disposition as an (a)(2) system. The team concluded that other (a)(1) evaluations reviewed were well supported and documented.

The systems were described in the "Maintenance Rule System Basis Document." This document was created by system engineers and reviewed by the MRC staff and the expert panel. The system basis document described the following: (1) the functions of the system relating to the maintenance rule; (2) risk significance determinations; (3) performance criteria and the applicability of those criteria; and (4) actual performance from July 1992 to July 1995. The team found the system basis documents to be a very useful tool to identify maintenance rule applicability to a specific system.

The river water (or station service water system for Unit 2) system included both the normally operating and standby systems. These water systems are risk significant. The systems were properly scoped and system boundaries adequately defined. For Unit 1, the normally operating river water system was (a)(1) and for Unit 2, the standby service water system was (a)(1). The team found that DLC's actions to improve performance were appropriate and the systems appropriately addressed under the maintenance rule.

The main feedwater, quench spray, and compressed air systems were categorized as (a)(2) systems. The system boundaries were properly defined. Risk significance was determined using PRA insights and expert panel judgement. The team noted that non-risk significant standby functions for some risk significant systems (i.e. quench spray and feedwater) were not clearly documented or in some cases not well understood by system engineers.

The switchyard is a normally operating non-risk significant system shared by both units. The team found this (a)(1) system to be properly scoped with adequate goals and corrective actions established. Monitoring was considered to be effective.

The team found that the DLC structures monitoring program was clearly defined in procedures and very well documented. There was one (a)(1) structure (Unit 2 safeguards building) and two risk significant structures (containment buildings). A qualified civil engineer evaluates each structure.

c. Conclusions

With some exceptions, the team concluded that the performance criteria for risk significant SSCs were appropriate and a link to the PRA assumptions was appropriately established. DLC's evaluation of the cumulative affect of the unavailability and reliability data on the overall plant CDF was acceptable.

Based on detailed review of specific SSCs, the team concluded that system engineers effectively applied the maintenance rule program to their systems. MPFFs and (a)(1) evaluations were properly evaluated and documented. The team concluded that the structures monitoring program at BVPS was strong and had resulted in one (a)(1) structure.

M1.4 Plant Safety Assessments before Taking Equipment Out of Service (IP 62706)

a. Inspection Scope

Paragraph (a)(3) of the maintenance rule states that the total impact of maintenance activities on plant safety should be taken into account before taking equipment out of service for monitoring or preventive maintenance. The team reviewed the procedures and discussed the process with the maintenance rule coordinator, the reliability engineer performing PRA risk assessments, licensed operators, and work planning department personnel.

The team also reviewed the equipment out-of-service (EOOS) logs and control room operators logs over a one month period for both units to determine risk significant "time windows" in which several SSCs were concurrently out of service. The review period was from June 1 through June 30, 1997.

b. Observations and Findings

The team reviewed the process and performance regarding risk assessment prior to removing equipment from service and found them to be effective. DLC incorporated the requirements to assess the impact on plant safety when removing equipment from service through Duquesne Light Company Nuclear Group Directive 1.8.14, "Maintenance Rule Program," Revision 0, System and Performance Engineering Administrative Procedure (SPEAP) 3.2, "Maintenance Rule Program Administration Administrative," Revision 2, and NPDAP 7.12, "Non-Outage Planning, Scheduling and Risk Assessment," Revision 4, which define the overall policy on the planning and scheduling of online maintenance.

Procedure NPDAP 7.12 addresses the process for work planning and scheduling activities. The procedure objectives as stated in Program Instruction IV-A is that all maintenance activities shall be planned and scheduled in a manner which provides for minimum out-of-service times, appropriate consideration of impact on overall plant safety, and efficient accomplishment of required maintenance. The maintenance is planned through a rotating 12-week schedule with input from system engineers, work planning personnel, operations personnel, and the PRA group. Based on interviews with planning personnel, the scheduling process is still evolving with an on-line maintenance improvement program to be implemented. The on-line maintenance manager stated that improvements are in progress for grouping of work activities to reduce unavailability and to improve efficiency. Several other enhancements in the planning process have been identified by DLC and are being made. Additional personnel have recently been added to the Maintenance Planning Department including two senior reactor operators (SROs).

The final work week schedule includes PRA insights as called for in NPDAP 7.12. Specifically, the Program Instruction IV-D of this procedure addresses the process for considering the safety impact of online maintenance activities. Program Instruction IV-E provides guidance on appropriate risk analysis techniques (e.g., PRA calculations or a pre-approved system risk relationship matrix) for evaluating risk impact on the plant when removing equipment from service for planned maintenance or surveillance activities. Quantitative analyses of online maintenance activities are accomplished by using the RISKMAN code to calculate CDF estimates of equipment-outage configurations identified in the preplanned work week schedules. Currently, the DLC PRA staff is performing risk calculations of equipment-outage configurations to produce daily risk profiles. The team validated a months worth of data associated with safety assessments when taking equipment out of service. Core damage probability (CDP) estimates of daily equipment-outage configurations are checked against the risk impact threshold of 1E-6 to avoid unacceptable risk levels. (The CDP limit of 1E-6 was proposed in the EPRI PSA Applications Guideline as a risk impact threshold). The team concluded that DLC effectively used PRA insights to minimize impact on overall plant safety in scheduling maintenance activities.

The risk impact of emergent work activities are reviewed by the PRA staff on a case-by-case basis. Program instruction IV-F of NPDAP 7.12 provides guidance for risk assessments in the event of emergent work for specific systems which may result in unacceptable risk levels. Operations personnel are required to communicate with the PRA group to determine the risk impact of equipment out-of-service conditions when emergent activities occur. Based on interviews with senior reactor operators, the team concluded that operators have a clear understanding on addressing emergent work and requirements for PRA input. The operations personnel have generally addressed emergent work activities appropriately; however, the team identified two examples (Unit 1 chilled water pump and Unit 2 component cooling water pump) where equipment was removed from service and not evaluated. An evaluation by DLC of these team-identified discrepancies showed only an insignificant increase in risk. The DLC PRA staff stated that the identification of emergent equipment removal by operations has not always been communicated to the PRA group in a timely manner. This problem had previously been identified during a self assessments and corrective actions to enhance administrative guidance had been recently incorporated. The team concluded that the corrective actions to address this problem were appropriate, but during this inspection it did not assess the effectiveness of the implementation of the corrective actions.

Shutdown risk is managed through the Administrative Procedure NPDAP 8.26, "Shutdown Safety/Outage Management," Revision 4. Risk is managed through the use of a key safety functions process that was defined in NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management." Currently, the DLC PRA group is using the IPE and IPEEE PRA models for evaluating risk impact of equipment out-of-service conditions at plant modes 2 to 5. DLC has not developed any outage risk assessment manager (ORAM) models for assessing the risk of system unavailability during plant shutdown conditions.

The team reviewed the equipment out-of-service (EOOS) logs and control room operator logs for both BVPS units to evaluate risk significant "time windows" in which several SSCs may have been concurrently out of service. None were found. In addition, the EOOS logs are utilized in accordance with SPEAP 3.2 and NPDAP 7.12 to monitor out-of-service durations. The out-of-service (OOS) times are provided by operations to system engineers to maintain a record of the total OOS times associated with specific systems and components. The team observed that operators effectively maintained the data base and system engineers appropriated applied the OOS times to their systems and components. The team noted that operations failed to account for OOS time for equipment surveillances when considering unavailability for maintenance rule purposes. NPDAP 7.12 described examples where surveillance times are not required to be accounted in OOS times (where recovery of the system is by simple manual operator action with an operator stationed locally); however, a review of surveillances was not conducted to determine which surveillances applied. The MRC stated that a review of surveillances will be conducted to determine appropriate out-of-service times.

The team noted that total OOS time is not expected to increase significantly with the review. The expert panel met on July 16, 1997, to discuss this issue. A review of surveillance tests will be performed and in those cases where the SSC can not be promptly returned to service, the SSC will be considered unavailable for maintenance rule purposes. The systems are properly considered inoperable with respect to technical specification requirements.

c. Conclusions for Safety Assessments

The team found that the process for assessment of the safety impact of removing SSCs from service for monitoring and preventive maintenance was good. The PRA group was actively involved in risk assessment activities for the online maintenance program. The team concluded that DLC effectively used PRA insights to minimize impact on overall plant safety in scheduling maintenance activities and in responding to emergent work activities.

M1.5 (a)(3) Periodic Evaluations and Balancing Reliability and Availability (IP 62706)

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. The rule also 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.

b. Observations and Findings

The team reviewed BVPS's periodic evaluation, *Maintenance Rule Periodic Assessment Input Report*, issued June 6, 1997. The report covered the period January 1996 through March 1997.

The assessment evaluated the performance of SSCs in paragraph (a)(1) of the rule as well as the continued appropriateness of the established goals. The report stated that SSCs generally performed acceptably against the established goals. Where systems had exceeded goals -- for example, a thermal barrier check valve in the primary component cooling water system at Unit 2 experienced a repeat failure during its flow test -- DLC initiated actions to correct the condition. DLC concluded most goals remained appropriate; however, they were in the process of adding additional goals for the switchyard system. This addition was based on inadvertent operation of a relay associated with a 345 kV bus that resulted in a dual unit trip.

For SSCs in (a)(2), the report stated plant personnel were effectively maintaining those systems. Some systems were considered for transfer to paragraph (a)(1); however, it was determined that performance concerns were not related to ineffective maintenance activities. For example, an intermittent stroking problem with containment penetration valves was caused by thermal expansion of the trapped water volume between the isolation valves. Disposition to paragraph (a)(1) was not warranted since the lack of relief protection for the penetrations was a design issue. DLC adequately addressed this condition by implementing design changes for both units that installed relief protection for the affected penetrations.

The report documented examples where industry operating experience (IOE) was used to improve plant performance. For example, changes were made to the emergency diesel generator governor PMs based on information from the vendor. The report also documented a few instances where effective use of IOE was not made. In one instance an ineffective evaluation of industry information regarding premature aging of a particular relay occurred. DLC reevaluated the information after relays experienced failures described in information notices, concluded the components were vulnerable to the failure mechanism described, and subsequently replaced the relays. DLC also issued a condition report to address ineffective use of IOE.

The assessment documented examples where the staff balanced reliability and unavailability. In one case, a ground protection relay problem resulted in a reactor trip and consequently was considered an unreliability event. Subsequent goals and corrective actions focused on improving system reliability through condition monitoring and outage activities, thus minimizing the effect on system availability. This approach improved reliability without adversely affecting availability. Conversely, a residual heat removal (RHR) pump experienced excessive unavailability due to a seal leak. The PM schedule was changed such that technicians performed oil changes and seal work during defueled conditions, thereby achieving zero system unavailability while improving reliability.

c. <u>Conclusions</u>

The team reviewed the periodic evaluation and noted that DLC assessed the performance of SSCs assigned goals under (a)(1); they demonstrated the effectiveness of preventive maintenance for SSCs under (a)(2); they typically took into account, where practical, IOE; and they appropriately balanced availability and reliability. The team noted that the evaluation was critical and identified weaknesses in performance. The team concluded the evaluation reflected a thorough approach and it met the requirements of paragraph (a)(3) of the rule.

M2 Engineering Support of Facilities and Equipment

M2.1 Review of Final Safety Analysis Report (FSAR) Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for a special focussed review that compares plant practices, procedures, and parameters to the FSAR descriptions. While performing the inspection discussed in this report, the team reviewed selected portions of the FSAR. The team verified that the FSAR was consistent with the observed plant practices, procedures and parameters.

M3 Staff Knowledge and Performance

a. Inspection Scope

The team interviewed engineers, managers, and SROs to assess their understanding of the maintenance rule and associated responsibilities.

b. Observations and Findings

The system engineers interviewed had very good knowledge of their systems and of the maintenance rule program and its impacts on their systems. The system engineers generally had a clear understanding of the performance criteria for their systems and the current status of the system with respect to the goals and performance criteria. The team found that the MRC's staff provided excellent support to the system engineers. The backup system engineers interviewed by the team were found to be knowledgeable of their backup systems. The senior reactor operators had a good overall understanding of the maintenance rule. Operations staff's responsibilities for maintenance rule functions were generally understood.

c. Conclusions

System engineers and senior reactor operators had very good overall knowledge of the maintenance rule and the specific applicable requirements to their duties.

M7 Quality Assurance (QA) in Maintenance Activities

M7.1 Self-Assessments of the Maintenance Rule Program

a. Inspection Scope

The team reviewed assessments which were conducted to determine if the maintenance rule was properly implemented.

b. Observations and Findings

The most recent assessment was performed by Quality Services during the period from April 11 through June 10, 1997. Their audit report was dated June 16, 1997. The team found the assessment to be thorough and resulted in the generation of thirteen condition reports. DLC was considered to be responsive to these findings.

c. Conclusions

The June 1997 audit provided a good assessment and identified some weaknesses. DLC appeared to be aggressive in addressing these weaknesses.

V. Management Meetings

X1 Exit Meeting Summary

The team discussed the progress of the inspection with DLC representatives on a daily basis and presented the inspection results to members of management at the conclusion of the inspection on July 11, 1997.

DLC indicated that some information provided to the team was considered proprietary. This information was returned to DLC.

PARTIAL LIST OF PERSONS CONTACTED

Duquesne Light Company

B. Williams, Maintenance Rule Coordinator
S. Jain, VP Nuclear Services
R. LeGrand, VP Nuclear Operations
K. Beatty, GM Nuclear Support
C. Hawley, GM Maintenance
B. Tuite, GM Operations
W. Kline, Manager Nuclear Engineering
K.Ostrowski, Manager Quality Services
J. Macdonald, Manager System and Performance Engineering
D. Orndorf, Manager Chemistry
L. Hawkins, Acting Manager Nuclear Safety
J. Kasunick, Manager Maintenance
T. Lutkehaus, Manager, Work Management
J. Arias, Director Safety and Licensing
C. Custer, Director Performance Engineering
B. Davis, Director System Engineering
T. Westbrook, Senior Structural Engineer
J. Belfiore, Quality Services Engineer
E. Knysch, Senior Quality Assurance Specialist
A. Hartner, Technical Assistant
K. Frederick, Supervisor PRA
S. Leung, Senior PRA Engineer

C. McFeaters, System Engineer Supervisor
T. McGourty, System Engineer
D. Slifko, System Engineer
R. Boyle, System Engineer
D. King, System Engineer
C. Hill, Senior Engineer
M. Pettigrew, System Engineer
L. Freeland, Technical Assistent
C. Keller, Senior PRA Engineer
P. Smith, Senior Engineer
B. Etzel, Senior PRA Engineer
B. Cherry, Senior Engineer
T. Cosgrove, Technical Assistent
P. Johnson, Consultant
G. Kurtz, Consultant
D. Beckman, Consultant

LIST OF INSPECTION PROCEDURES

IP 62706, Maintenance Rule
IP 62002, Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants

LIST OF ACRONYMS

AOP - Abnormal Operating Procedure
BVPS - Beaver Valley Power Station
CDF- Core Damage Frequency
DCP - Design Change Package
DFP- Dedicated Feedwater Pump
DLC - Duquesne Light Company
EOP - Emergency Operating Procedure
ERF - Emergency Response Facility
DC- Direct Current
FF- Functional Failure
IP- Inspection Procedure
IPE- Individual Plant Evaluation
IPEEE
FV- Fussall Vesely
MEL - Master Equipment List
MRC- Maintenance Rule Coordinator
MPFF- Maintenance Preventable Functional Failure
NEAP - Nuclear Engineering Administrative Procedure
NPDAP - Nuclear Power Division Administrative Procedure
PRA - Probabilistic Risk Assessment
QA- Quality Assurance
RAW- Risk Achievement Worth
RSS- Recirculation Spray System

RG - Regulatory Guide
RWS - River Water System
SPDS - Safety Parameter Display System
SPEAP - System and Performance Engineering Administrative Procedure
SSCs - Structures, Systems and Components
SSST - System Station Service Transformer
SWE - Standby Service Water System
SWS - Service Water System
UPLC - Unplanned Capability Loss Factor
UFSAR - Updated Final Safety Analysis Report