Overall, the housekeeping and material condition of safety related systems were good. However, the deficiencies and potentially adverse conditions identified suggested that standards of good housekeeping and material conditions were more rigorously implemented at Unit 2 than at Unit 1. Some problems, such as borated water leakage from valve packing, in areas of lower visibility were long-lived. Maintenance planning was effective as demonstrated by the successful accomplishment of corrective and preventive activities. Planning meetings contributed to effective maintenance. Surveillance testing schedules were properly implemented. The voluntary entry into TS action statements for maintenance and surveillance on safety systems was not controlled to assure that the net safety benefit from removing safety systems from service was thoroughly assessed. Backlogs were managed within established goals and actions were in progress to better manage the preventive maintenance backlog and to reassess the priorities assigned to outstanding items. Trending of equipment failures and out-of-service times for safety systems was adequate.

The team observed that the system engineers development and expertise, and ability to respond to emergent issues appeared to be improving as this organization gained experience. The System Engineering assessment of performance trends was good. Inservice testing identified degraded conditions prior to failure. Some trend assessments varied in analytical rigor and did not lend easily to an effective management format. Although no safety concerns were identified, weaknesses were observed in the management and implementation of the basis for continued operation (BCO) program resulting in inconsistent justifications, limited assessments of safety significance, and lack of documentation rigor. The administrative procedures for the BCO program were recently revised to address these issues.

Maintenance procedures provided good detail and included proper management reviews, acceptance criteria, and a mechanism to elicit procedure improvement suggestions. NRC review of deferred post-maintenance testing identified no concerns. Field observations of maintenance verified that personnel were knowledgeable of activities performed. Work and surveillance packages were well planned and contained adequate detail. Engineering and supervisory oversight contributed to quality maintenance.

The team concluded that the various station programs to identify, assess, and resolve plant deficiencies and personnel performance issues were satisfactory. Problem identification was accomplished by a variety of mechanisms and the threshold for entering items into these various programs was appropriate. Root cause analysis for station events was adequate. The limited application of detailed causal analysis processes for personnel performance deficiencies was considered a significant weakness that warrants management attention. The corrective action programs (tracking and closure) were considered good, however, the increasing trend in personnel performance errors indicates that corrective actions taken, to date, have not been totally effective. Recent personnel performance improvement initiatives have been taken, but could not be assessed.

The team concluded that Quality Services Unit (QSU) audits and surveillances of various plant activities were comprehensive, of good technical quality, and were well documented. The team determined that the QSU assessment processes and the QSU audit program were effective largely due an experienced and knowledgeable QSU staff. Recent QSU initiatives to verify corrective action implementation were determined by the team to be a good effort for assuring thorough reviews. Reviews and assessments of plant activities by the Onsite Safety Committee, Offsite Review Committee, and Independent Safety Evaluation Group were satisfactory. The team concluded that adequate measures had been established to provide effective oversight of plant activities. A failure to conduct Technical Specification audits per the required schedule was subject to enforcement discretion.

DETAILS

1.0 INSPECTION OBJECTIVES AND SCOPE

The inspection team activities consisted of one week of preparation in the Region I office reviewing documentation requested by the team and two separate weeks on site (February 28 to March 4, and March 14 to March 18) with the intervening week spent reviewing programs and technical information gathered during the first week on site. The team's findings were reviewed by NRC regional management and presented to the Beaver Valley Power Station management at the exit meeting held on site March 18, 1994. The detailed findings and conclusions of the team are documented in this inspection report.

2.0 DETAILED INSPECTION FINDINGS

2.1 Engineering and Technical Support

The team assessed the effectiveness of the engineering staff at the site by reviewing the organizational structure, staffing, engineer staff training, permanent plant modifications, temporary modifications, and observance of the day to day workings and communications among the various engineering groups. The team also interviewed engineering managers and staff members.

2.1.1 Engineering Organization and Staffing

The Duquesne Light Company (DLC) Nuclear Engineering Department (NED) is composed of approximately 165 engineers, designers, and supervisory personnel organized into six functional areas. This staff includes both DLC and contract personnel and provides the technical expertise for the day-to-day support of plant activities and for the development of all plant modifications and design changes. The NED staff reports to the Vice President of Nuclear Services through the Nuclear Department Manager and the various functional area directors. Day-to-day support of the operations and maintenance departments is provided via the system engineering and component engineering staffs recently placed under the supervision of the General Manager of Maintenance Programs Unit. The team determined that the engineering organization was fully staffed and organizational responsibilities were clearly established.

2.1.2 Engineering Staff Training

The engineering staff training program is governed by Training Administrative Manual Volume 2, Chapter 5. All engineering support personnel must complete forty days of orientation training which includes general classroom and plant systems training. In addition, each engineer was required to complete a job-specific qualification checklist for their position. Continuing training was provided annually by both the training department and each functional engineering group. Continuing training included discussion of recent plant events, modifications, and industry events. The team reviewed several continuing training modules and considered the continuing training program a strength. Lesson plans reviewed by the team were thorough and well organized. Qualification training for NED engineers was considered adequate and the overall engineering staff training program was considered thorough and well controlled.

2.1.3 Engineering Management Oversight

The team reviewed the management oversight of the engineering organization. Specifically the team assessed the adequacy of administrative guidance and the implementation of administrative programs to ensure that significant technical safety issues were resolved by the engineering organization in a timely manner.

The team reviewed the Beaver Valley Business Plan and its subordinate 1994 Nuclear Division Action Program and 1994 NED Objectives and Goals. The team found the Business Plan to be current and detailed. However, the team found the Nuclear Division Action Program to have provided few clear goals and objectives directly related to the NED organization performance. In addition, the goal for control of the Engineering Memorandum backlog did not appropriately designate NED as having responsibility and accountability for it's achievement. The NED management had developed more specific NED Objectives and Goals. The team found that the 1994 NED Objectives and Goals were consistent with the objectives of the Nuclear Division Action Program. The development of 1994 NED Section Goals were under development at the time of the team inspection and the team considered this to be a positive initiative. However, the team noted the absence of any formal guidance for developing the above-mentioned goals and objectives and for the monitoring of the engineering staff's success in achieving these goals. The team reviewed the Unit 1 and 2 Long Range Plans and concluded that they provide effective tools for developing and implementing long-range plant modifications and for coordinating major plant evolutions like refueling outages.

The NED established the Engineering Assurance (EA) section to conduct independent reviews, evaluations, assessments, and analyses of their technical and administrative activities independent of Quality Services Unit (QSU) assessments and audits. The EA section was initiated to improve the overall quality of NED activities. The EA section advises the NED Manager of any noncompliance identified as a result of their reviews. The scope of review for the EA section includes NED personnel training, vertical slice evaluations of NED activities, all new and revised NED administrative and technical procedures, EA trend and status reports, root cause determinations, all audits, inspections, and evaluation reports related to NED, and NED required responses to identified deficiencies.

The team reviewed a June 1993 EA project report involving a root cause evaluation assessment. This review concentrated on evaluating the processes involving Technical Evaluation Reports (TERs) and Design Change Packages (DCPs) to determine the reasons for recent NED noncompliances with administrative requirements. The noncompliance had been identified by QSU audits. The team determined that the findings from this evaluation were clearly presented and appropriate recommendations had been made to address these findings.

The team identified that since the EA section was established in December 1992, no program implementing procedures or evaluation guidance has been established by NED management. However, the team concluded that the EA section had conducted thorough reviews and made good recommendations based on their findings. Assessments reviewed by the team were determined to have had a positive impact on NED activities. The team concluded that NED management oversight of the EA section could be strengthened by developing procedures and formal evaluation guidance.

The team reviewed evaluations conducted by Engineering Management Services to assess the effectiveness of the design review process. These evaluations included review of changes made to DCPs at the end of each outage. These changes included engineering change notices (ECNs) and field change notices (FCNs). Nuclear Engineering Administrative Procedure 7.1, "Corrective Actions," requires a review to identify and trend root causes of changes to DCPs. However, review by the team of two Engineering Management Services evaluations following the Unit 1 ninth refueling outage and the Unit 2 fourth refueling outage identified that root causes for determining the reasons for DCP changes had not been performed. Although the number of ECNs/FCNs were tracked and trended, the team determined that more thorough root cause evaluations were needed to better evaluate the effectiveness of the design review process. The team noted that at the time of this inspection, the EA section was conducting a more detailed evaluation of the ECNs/FCNs generated as the result of DCPs.

The biennial review of NED procedures is required by Nuclear Power Division Administrative Procedure (NPDAP) 2.3. The team determined that the biennial reviews were not being conducted per the schedule. Discussions with NED management indicated that they were aware of this oversight and that plans to eliminate the overdue reviews were in place. Overdue procedure reviews for the months of January and February 1994 were 13 and 14, respectively, but were reduced to a total of five by the end of the team's on site inspection. Actions taken by the NED staff to complete overdue procedure reviews were found to be satisfactory by the team.

In summary, the team determined that the EA section had a positive impact on the performance of the NED. However, the NED guidance for the development of organizational goals and objectives for EA section activities was not developed. The team noted several examples of a lack of attention to detail in the implementation of administrative procedures. The lack of attention to detail was evident in a number of programs and processes reviewed and detracted from the overall quality of NED work. However, the team concluded that the lack of attention did not result in conditions adverse to safety. Safety significant issues were being addressed in a timely manner.

2.1.4 Permanent Modifications and Safety Evaluations

The station modification process is described in a variety of plant procedures. To evaluate the plant modification process, the team reviewed these procedures and examined a number of modification packages (both closed and open, major and minor, and design equivalent types). For each modification package, the team evaluated the adequacy of the modification to resolve identified deficiencies or to achieve the desired enhancement, assessed the acceptability of safety evaluations, reviewed the implementation process (including post-modification testing), examined the process for returning the system to the operation, revision documentation process, and assessed the tracking for closure of identified open items. For selected modifications, the team interviewed the responsible engineers.

The team found the procedures controlling design changes and plant modifications to contain sufficient detail and guidance. The instructions were clearly written and supported by flow diagrams. The packages reviewed were, in general, well organized and prepared in accordance with the appropriate procedures. The modifications adequately met their intended purpose. The quantity of ECNs and FCNs included within the packages was typically low, indicating adequate preparation during the design phase of the project. Only one modification package (DCP-1698) contained significantly more ECNs and FCNs than other modifications reviewed, indicating a less than adequate engineering and front-end design effort.

The team review of several safety evaluations found them, in general, to be detailed, technically sound, and documented in accordance with the Nuclear Group Administrative Procedure (NGAP) 8.18, "10 CFR 50.59 Evaluations." Each evaluation that was reviewed satisfied the 10 CFR 50.59 requirements and provided an adequate basis for determining that an unreviewed safety question was not involved with the modification. Improvements were noted in the documentation of more recently completed safety evaluations. Engineers interviewed by the team were knowledgeable of their assigned modifications and of the modification process.

Although the overall implementation of the modification process was good, the team identified several minor discrepancies that were indicative of a lack of attention to detail. For example:

1. In conjunction with the deletion of an automatic start signal for the Unit 2 steam driven auxiliary feedwater pump (DCP 1633) NED prepared two calculations. The purpose of the first calculation, No. 10080-DMC-0106, was to determine the mechanical analytical limits to be used in the setting of the pressure switch 2FWE*PS158A in the discharge line of the pump. The second calculation, No. 12241-FWE*6-3-C, was prepared to evaluate the instrument loop accuracy and to establish the setpoint of the pressure switch. Review of these calculations found that they had been prepared by different engineers and that the second calculation was issued eight days before the issuance of the first calculation and, therefore, without

final supporting results. Discussions with the responsible engineers indicated that some communication had occurred between them during the preparation process, but the final and slightly different results of the first calculation were neither provided to nor solicited by the second engineer. Notwithstanding, the team review of both calculations found the pressure switch setting to be acceptable.

2. The Unit 1 inverters replacement was documented in DCP 1531. DCP 1531 was supported by Calculation 08700-DEC-0135, which evaluated the current fault level at various 480 Vac loads. Team review of the analysis found the comparison between the breaker fault interrupting rating and the calculated available short circuit current to be inappropriate, in that, the fault had been assumed at the end of the cable rather than at the breaker terminals. This discrepancy means that, if the assumption was correct, the fault interrupting rating of the breakers might be exceeded. NED indicated that the analysis used a simplified method and conservative assumptions.

3. TER 6900 evaluated the replacement of an ASCO model HPX8320A26 solenoid valve with an equivalent valve, ASCO model NP8320A186E. The evaluation properly addressed the valve physical and environmental characteristics. However, the analysis failed to establish a qualified service life. Although the solenoid valve performs its safety function within a minute from the onset of an accident, it is normally energized and it is subject to heat degradation. Therefore, its capability to function on demand should have been established.

4. The post modification test specified in DCP 1377, "Pressure Reducing Orifices for AFW Pump Lube Oil Cooler Lines," was not appropriate and two ECNs were issued to supplement the originally specified post modification test. In addition, the test results of this post modification test were not thoroughly evaluated. The measured flow through the oil coolers was less than the design flow, and the specified test acceptance criteria was not well established. The engineering staff had reviewed the testing data, but the team concluded that they had not thoroughly evaluated the results. The engineering staff subsequently provided the team with a calculation that verified the original assumption that the reduction in flow would not adversely affect the oil cooler performance.

(For items 1, 2, and 3 above, the NED staff provided preliminary analysis to satisfactorily address these items. The NED staff stated that further action would be taken to properly document these items. For item 4, the team found the calculation satisfactory.)

The team found that the post-modification testing for the modifications examined to have been generally acceptable. The team noted a number of post-modification test program enhancements implemented by the station staff in response to lessons learned from the emergency diesel generator load sequencer failure. The team was unable to assess the effectiveness of these new testing enhancements because of the short period of time that they had been in place.

2.1.5 Temporary Modifications

Selected temporary modifications were reviewed to verify that they were implemented and controlled in accordance with station procedures and regulatory requirements. The team also verified that the temporary modifications had been adequately evaluated for impact on plant safety systems.

Temporary modifications are controlled in accordance with Nuclear Power Division Administrative Manual, NPDAP 7.4, "Temporary Modifications." This procedure provides detailed guidance for controlling temporary modifications. The total number of active temporary modifications was 11 and 15 for Units 1 and 2, respectively. The review and approval, technical adequacy, installation, and tagging of selected temporary modifications were verified to be in accordance with NPDAP 7.4. The engineering department actively monitored the status of temporary modifications. The engineering staff provided timely permanent design changes when required to resolve active temporary modifications. The team noted one case where a temporary modification that installed a new wide range reactor coolant pressure recorder in March 1993 had not been documented on a routing slip as stated in NPDAP 7.4. The temporary modifications are routed to the technical staff to ensure that the temporary modification would not adversely impact a pending design change. The engineering staff completed the routing of these temporary modifications prior to the completion of this inspection.

The team concluded that the administrative procedures for temporary modifications were detailed, and that the temporary modifications reviewed had been installed in accordance with these administrative procedures. The engineering department management's attention to resolve active temporary modifications and to maintain the total number of active temporary modifications low was a strength. The team concluded that the failure to route the temporary modification to NED was an example of inattention to detail.

2.1.6 Engineering Work Backlog

The team reviewed NGAP-2.17, "Workload Priority System," which describes the process for identifying and prioritizing engineering activities at the station. The procedure is applicable to engineering memorandums (EMs), station modification requests (SMRs), DCPs, TERs, and special projects. The team found the EM prioritization system defined by NGAP-2.17 to be a workable system, but the implementation for EMs was found to be less than fully effective and inconsistently applied. The assigned priority for a given task is the sum of numerical values entered into the system by the managers responsible for the task prioritization. The numerical values are clearly defined in NGAP-2.17 and are based on criteria that take into account benefit/cost and the impact of the modification on plant safety, performance, and regulatory compliance. Consequently, the effectiveness of the system is dependent upon each manager's evaluation of the task and the timeliness of their evaluation.

Team review of a February 15, 1994, monthly status report found that of the 422 reported open EMs only 41 had undergone prioritization review by the responsible managers. Some EMs that had undergone only partial review had targeted review completion dates that were overdue by more than a year. A review of the description of the open EMs showed that the great majority of them addressed what appeared to be non-safety related issues and components, but a small percentage were clearly safety related issues. Following NRC discussion of this observation with NED management, this backlog was significantly reduced. Discussions with NED management determined that they did not consider the lack of timely review of EMs to be a significant safety concern. This was based principally on the premise that the more safety significant issues are typically discussed and consequently driven by morning meetings attended by station management. The team's concern with the reliance on the morning meetings was that an issue not clearly recognized as safety significant by the EM preparer might not be properly characterized and presented at these meetings.

The team also evaluated the backlog of EMs, SMRs, DCPs, and TERs. A review of the periodically prepared graphs and trend reports indicated that the backlog of these items appeared to have remained approximately constant during the last two years. However, the age of the open items appeared to be increasing. The team did note that plant drawings were being updated in a timely manner and that the backlog of vendor manual updates was decreasing. The vendor technical information process was also considered effective in maintaining vendor manuals and documents current.

The team concluded that, in general, the engineering work backlog was reasonable and well monitored. However, additional management attention was needed to ensure that the EM backlog is properly evaluated.

2.1.7 Selected Technical Issues

2.1.7.1 Unit 2 Emergency Diesel Generator

The Unit 2 emergency diesel generators require control air for the air-operated jacket water thermostatic valves. In the event of a loss of the control air, the valves are designed to go to full cooling position allowing full jacket water flow. The diesel manufacturer recently communicated a concern regarding this failure mode of the valve and a potential overcooling of the engine under extreme external conditions. To address this issue, NED prepared Calculation No. 10080-DMC-0108 in August 1992 to establish the control air availability from the storage tanks following the loss of the air compressor. In this calculation, based on a manufacturer's published air consumption rate of 1.5 standard cubic feet per minute (scfm) adequate control air supply to the temperature control valves was available for six hours.

A basis for continued operation, issued August 13, 1992, stipulated operator intervention might be required within six to eight hours. In addition, the emergency operating procedure (EOP-A.1.6) was revised to require a once per shift surveillance of the jacket water temperature while the EDG was in operation. If a loss of control air condition exists, engine jacket water temperature is to be maintained by throttling the diesel generator heat exchanger outlet isolation valve to maintain temperature between 95°F and 138°F.

As a result of problems experienced with the No. 2-1 diesel generator air system (reference problem Report Nos. 2-94-034 and 2-94-036) two leaky relief valves were replaced. Prior to replacement, air consumption by these devices was measured and found to be between 3 to 4 scfm. The team concluded that this measured leak rate potentially invalidated Calculation 10080-DMC-0108 and that a complete evaluation of the recently identified leak rate results had not been initiated by NED. As a result of the discussions between the team and responsible NED engineers a revision of the calculation was initiated. The revised calculations indicated air availability for approximately 1.5 hours vice 6 hours. Consequently, a new basis for continued operation was written and a special operating order was issued directing the operators to check the air tank pressure every 1.5 hours of EDG operation, if control air pressure drops below 200 psig.

The team's detailed review of the above issue identified several other related concerns (i.e., (1) lack of periodic testing of the diesel starting air check valves; (2) questionable capability of the butterfly valves to throttle water flow through the diesel jacket water heat exchanger, and (3) failure mode of the cooling valve associated with high head charging pump lube oil system. Regarding the EDG check valve testing, the NED staff indicated that requirements would be instituted to periodically test the check valves. Regarding the throttling of the butterfly valves, a preliminary analysis showed that the valves would have to be closed approximately 90% before enough differential pressure would be developed to initiate valve cavitation and damage. The licensee also stated that they would evaluate the feasibility of replacing the air-operated valves with temperature-controlled valves. Lastly, preliminary evaluations of the charging pump cooling valve failure mode determined that cooling valve failure (full open) would cause temperature to drop only a few degrees below the recommended level. However, this would still be well above the acceptable temperature specified by the pump manufacturer. The NED staff indicated that they would continue to evaluate this issue.

2.1.7.2 Rosemount Transmitter Replacement

Team review of DCP 791 identified that it was issued to replace two Rosemount transmitters, PT-LM-101A and -101B, both of which had a qualified service life of ten years. A review of the modification package identified that station modification request (SMR) No. 1065, dated September 15, 1986, specified that the qualified life had expired in 1991, but that the transmitters had not been replaced until the latter part of 1992. The team identified the discrepancy to the licensee and asked whether a justification had been prepared for extending the service life of the transmitters beyond their qualified life. The licensee had not calculated the plant specific qualified life and had not developed a justification for extending the service life. In response to this observation, NED prepared Calculation 8700-OQC-0079. This calculation showed that the site specific qualified life of these transmitters was 14.6 years. The team concluded that the replacement of the transmitters in 1992 was acceptable.

2.1.8 Procurement and Dedication Process Review

The team reviewed some of the activities related to the dedication of items procured as commercial grade. The review included the dedication of the recently failed ATC-type timers, the disposition of components purchased before 1989 and stored in the warehouse, and the dedication of a Kunkle valve that is used to regulate the pressure in the emergency diesel generator (EDG) engine. The team also reviewed audits performed by the licensee of procurement and dedication activities.

2.1.8.1 Commercial-Grade Dedication of ATC-Type Timers

The team reviewed the commercial dedication of Type 365A ATC timers used in the EDG load sequencer at Unit 2. These timers had failed during earlier surveillance tests. The failure of the load sequencer was the subject of a NRC Augmented Inspection Team (NRC Inspection Report 50-412/93-81). The load sequencer acts to block the automatic start of equipment from the bus and permits the loads to be placed on the bus in six discrete, timed steps, over a 1-minute period. Such a sequenced loading of the emergency bus prevents the overloading of the EDG. On November 4, 1993, during the performance of Operating Surveillance Test (OST) 36.3, "Emergency Diesel Generator Automatic Test," the Train-A, 2-1 EDG load sequencer failed to automatically load the emergency core cooling systems (ECCS) on the 4 kV emergency electrical bus, as designed.

The team determined that the staff of the Nuclear Engineering Department (NED) had prepared Design Change Package 1545 (DCP 1545) to remove the existing ATC Type 305E motor-driven analog reset timers, because they were experiencing drifts in the time delays and to replace them with ATC Type 365A timer/relays. To procure the ATC timers, the licensee used Procurement Specification 10080-DES-0123, Revision 1, of June 6, 1990, "Engineering Service Scope of Work (ESSOW) for Environmental Qualification of ATC Type 365A timer/relays, with Resistors and Mounting Hardware." 10080-DES-0123 specifies the technical and engineering services necessary to quaiify ATC type 365A timer/relays to the requirements of the Institute of Electrical and Electronic Engineers (IEEE) Standard 323-1974 as interpreted in NUREG-0588, Revision 1, and IEEE 344-1975.

A detailed review of specification 10080-DES-0123 by the team determined that it did not explicitly stipulate the critical characteristic of the timer/relay, namely, that the ATC Type 3650 A timer/relays contacts would be subjected to inductive loads during operation. Therefore, Wyle Laboratories, which qualified the timer/relays to the requirements of IEEE 323-1974, may not have exercised the contacts of the ATC Type 3650 A timer/relays to simulate the energization and deenergization of relay coils during the tests. Additionally, there were no procedural requirements (as part of commercial dedication) to perform post-installation tests to verify that the timer/relay contacts will successfully withstand the inductive loads generated by the energization and deenergization of relays in the circuitry. In applications in which a commercial grade timer/relay is installed in a complex circuitry, successful commercial grade programs specify post-installation tests to verify the operation of the entire sequencer circuit. The team concluded that the dedication of the relays was not appropriate. The licensee performed extensive testing of the relays, following the failure, to supplement the original dedication process.

2.1.8.2 Review of Dedication Activities on Commercial-Grade Stock Items

In a letter, dated March 27, 1992, the licensee informed the NRC that it planned to implement an evaluation program in response to NRC observations documented in Inspection Report 50-334/91-201 and 50-412/91-201. The licensee planned to evaluate all stored commercial grade materials that had been purchased before 1989 and had not been dedicated to current standards. The evaluation would provide reasonable assurance that there had been no problems that would render a component unsuitable for service. The reclassification was required because the material was purchased as a commercial grade item (CGI) and was required to be upgraded to the status of a safety related item.

The Procurement Engineering Department (PED) was assigned the responsibility to evaluate and resolve this issue. PED documented this evaluation by initiating Deficiency Report 761. The items were placed in two categories.

For the first category of items, PED was able to locate purchase orders to indicate that the item was purchased as safety related and was able to find Certificates of Conformance (CoCs) for them. For the other category of items, PED hired a consultant to determine if the items had in the past performed poorly or were problem items. For those items that had performed satisfactorily, the bases used to determine that the item was upgraded to safety related status was documented.

Typical items, which the consultant resolved, were spare components for Cyberex type battery charger and fuses. For these items, the consultant determined that there were no industry bulletins or NRC information notices notifying that there were problems with these components. The team reviewed 60 items and determined that the methodology used to reclassify the items met the intent of the licensee's plan outlined in its letter of March 27, 1992, to the NRC.

2.1.8.3 Dedication of Kunkle Valve

Maintenance Work Request No. 27911 involved the replacement of a Type 39A relief valve that regulated control air pressure to the emergency diesel generator (EDG) engine. The Type 39A relief valve was manufactured by Kunkle Valve Company, Fort Wayne, Indiana, and had been supplied by Colt Industries (Colt), the manufacturer of the EDG. The valve leaked, and its lift setpoint drifted. A technical evaluation determined that a Kunkle relief valve Model 548-A was an equivalent to the obsolete Model 39A valve. The licensee asked Colt to clarify its statement on its drawing "substitutes not permitted." Colt clarified that the statement was an internal directive to its purchasing department to "discourage price shopping." The station purchased the Model 548-A Kunkle valves and performed commercial dedication by testing the valves. The team found that the dedication of these valves was acceptable.

2.1.8.4 Review of Audits and Corrective Actions for Commercial Dedication and Procurement Activities

The team reviewed selected corrective action requests (CARs), LERs, and audits to determine if appropriate and timely actions were taken by the licensee to correct conditions adverse to quality involving procurement related activities. The following items were reviewed: CAR No. 93-02; Unit 1 LER 93-008; Audit BV-C-90-51; Audit BV-C-90-35; and various audits performed on a qualified supplier. The team found that audits of station procurement activities were thorough. Actions taken by the licensee in response to identified adverse quality conditions, with only minor exceptions, were proper and timely. Audits performed by the licensee or its agents of qualified suppliers were also found to be thorough, with appropriate corrective action taken for identified problems.

2.1.8.5 Review of Actions Taken On NRC Information Notices

The licensing staff of the Nuclear Safety Department (NSD) has the responsibility to review information notices (INs) issued by the NRC. NSD utilizes Chapter 9 of Volume II of the Nuclear Safety Administrative Manual for performing reviews, for distributing material, and for preparing internal responses to NRC INs. The team reviewed the resolution of the following INs:

- IN 93-68, "Failure of Pump Shaft Coupling Caused by Temper Embrittlement During Manufacture."

- IN 93-65, "Reactor Trips Caused by Breaker Testing with Fault Protection Bypassed."

- IN 93-58, "Nonconservation in Low-Temperature Overpressure Protection for Pressurized-Water Reactors."

- IN 93-38, "Inadequate Testing of Engineered Safety Features Actuation Systems."

- IN 93-26, "Grease Solidification Causes Molded Case Circuit Breaker Failure to Close."

- IN 93-09, "Failure of Undervoltage Trip Attachment on Westinghouse Model DB-50 Reactor Trip Breaker."

The team determined from the available documentation that appropriate actions were taken by NSD to address the issues identified in the above NRC INs.

2.1.9 Conclusions

The team concluded that the engineering organization adequately supported the operation of the plant. The team also found that the license had instituted programs to improve the performance of the engineering organization, but the implementation of these programs was not always effective. In the area of design change processes, the team found the administrative procedures provided adequate detail. The implementation of the modification processes was also good. However, several minor discrepancies were observed, both in the design and the implementation processes. Safety evaluations were typically detailed with improvements noted in the more recently completed evaluations. The temporary modifications were few and well controlled. In the engineering work backlog area, the team found that adequate mechanisms were in place to prioritize engineering activities, but that the prioritization of EMs was not being implemented in a timely manner. The team also observed that while the quantity of work appeared to remain approximately constant during the last two years, the age of the open items appeared to slightly increase. Vendor technical information and design documents were updated in a timely manner. Review of selected aspects of the procurement and commercial grade dedication processes found them to be satisfactory. Audits in this area were found to be good and associated corrective actions for identified problems were also considered appropriate.

2.2 Maintenance Review

The team reviewed selected aspects of the station maintenance program. The maintenance area review included processes and procedures for the conduct of preventive, predictive, and corrective maintenance, and the observation of maintenance and maintenance related activities in the field. The assessment of the maintenance program was performance-based and considered material and housekeeping conditions, engineering technical support, and management oversight.

2.2.1 Plant Housekeeping and Material Condition

The team performed plant walkthroughs and inspected safety systems to assess the material condition of safety-related structures, systems, and components (SSCs). Potentially degraded conditions and poor housekeeping practices were presented to the licensee for evaluation. Overall, good material conditions and housekeeping were observed. However, based on team observations, some potentially adverse material conditions existed in the high head safety injection (HHSI) and hydrogen recombiner rooms of Unit 1.

On all three HHSI pump lube oil heat exchangers significant surface marring was observed on the pipe coupling for the river water (RW) supply line. This condition appeared to be caused by the use of excessive force for pipe assembly/disassembly and indicated either poor quality workmanship or system alignment difficulties. The team was concerned that the marring represented the use of excessive force that potentially generated residual stresses invalidating piping design analyses or increased the likelihood of fatigue failure. Engineering evaluations were in progress at the end of the inspection period to assess the condition. In the "C" HHSI room, a cantilever beam overhanging the HHSI pump was missing a mounting bolt. The licensee determined that the support base was over-stressed and a maintenance work order (MWO) was generated to restore the beam support to as-built specifications. In the hydrogen recombiner room, temporary power supply cables, supported by cable trays located above safety related hydrogen recombiner components were observed. An engineering evaluation did not exist that assessed this type of cable tray loading and the licensee had them removed.

Examples of poor small valve maintenance and degraded pipe insulation were observed. Boron encrustation on valve packing glands (HHSI and boron injection systems) and shaft seal hold-down bolts (quench spray pump) indicated a potential concern for corrosion. Radiological drip containments in the HHSI room installed to collect leakage from the valves indicated that they were installed for a long period of time based on dry surfaces, the amount of boron encrustation, and the accumulation of dirt and debris inside the drip containment. The team observed the components in the vicinity of the boron encrustation and did not identify any corrosion of plant equipment.

In the areas where the station staff focused, housekeeping was good. However, a few examples of poor housekeeping in lower traffic areas were noted. A roof leak in the hydrogen recombiner room represented poor housekeeping and a potential water source for electrical faults, catalyst for piping corrosion, and a potential personnel safety issue. Based on the water stains on the floor, this leak appeared to have existed for a period of time. Beneath the HHSI pumps, excessive oil accumulation in the drip pans fully soaked the absorbants and increased the relative fire potential of the area. A tygon hose was stored on recirculation spray piping, and tools and general debris were found around the HHSI pumps. Marginal housekeeping was also observed near a boron injection tank in Unit 1. Boron encrustation on valves tended to mask degrading leakage and make-shift coffer dams were installed on the floor to minimize the spread of contaminated water. When this latter condition was brought to the attention of the Maintenance Engineering and Assessment Department, sensitivity was not demonstrated in determining the cause of the leakage, indicative that floor contamination in this area was being tolerated.

Overall, the conditions identified above did not adversely affect safety system operability. Safety related piping, system supports and foundations, and valves were generally well preserved. The storage of combustible materials was controlled and evaluated against the station fire hazards analysis. The storage of temporary materials did not reduce accessibility to systems and components. However, the team concluded that a number of deficiencies had existed for a long period of time potentially representing a lack of sensitivity to the need for good housekeeping and material conditions in specific areas of Unit 1. In the areas in which the licensee focused, namely Unit 2 and highly visible areas of Unit 1, conditions were generally very good.

2.2.2 Ventilation System Walkdown

Unit 2 ventilation supplies cool filtered air to safety-related electrical switchgear and components important to plant safety. A team walkdown of the Unit 2 ventilation system identified no conditions that would diminish the operability of this system. Damper and fan motor inspections verified adequate lubrication and alignment. Actuators exhibited freedom of motion and ventilation duct insulation was intact and continuous. The team verified that preventive maintenance lubrication program for the ventilation equipment reviewed was adequate.

2.2.3 Maintenance Planning

The team reviewed the maintenance planning programs to determine their effectiveness in scheduling the repair of degraded equipment and surveillance testing. The maintenance planning program was specified by Administrative Procedure 4.5, "Daily Maintenance Planning and Scheduling." The team concluded that maintenance planning schedules were effective as demonstrated by the successful completion of corrective and preventive activities within windows established by daily and weekly schedules. A pre-planned schedule, called the Daily Schedule Report (DSR), identified particular activities by description, procedure, and MWO. Estimated start and finish dates and the responsible department were assigned. The DSR received appropriate distribution and plant personnel demonstrated ownership for their particular areas of responsibility. The team compared the Operations Department surveillance schedule to the DSR and determined that surveillances were performed as scheduled. The accomplishment of operations surveillance tests (OSTs) was documented by signature and date on both the surveillance and OST schedule; this was considered an element of good program management.

The daily planning meetings observed were chaired by either the unit Operations Manager or unit Nuclear Shift Supervisor. Meetings observed by the team demonstrated appropriate management involvement, good coordination of actions to correct emergent and multi-disciplined issues, and appropriate review of routine maintenance and surveillance testing activities.

2.2.3.1 Preventive Maintenance at Power

The team reviewed the mechanisms used by the station for the control of preventive maintenance at power. These controls were compared to the guidance provided to the industry via Generic Letter 91-18 and NRC Inspection Manual, Part 9900, "Maintenance - Voluntary Entry into Limiting Conditions for Operation Action Statements to Perform Preventive Maintenance."

The team determined that the station does remove Technical Specifications (TS) safety systems from service during power operations to conduct preventive maintenance (PM). For example, the auxiliary feed pump (1FW-P-3A) and recirculation spray pump (RS-P-2B) was removed from service on February 16 and March 15, respectively, for pump and motor PMs. These component outages were planned a week in advance to coincide with surveillance testing to limit operational cycles and out of service time. Pump PMs are typically conducted every 12 to 18 months based on vendor recommendations and performed within an eight-hour window. These PMs generally include the changing of lubrication oil, which renders the safety systems out of service. The team learned that the incorporation of corrective maintenance (CM) within the PM/OST planning windows was routinely considered by the cognizant planner. Final job packages, including the scheduled maintenance from the mechanical, electrical, and instrument & controls departments, were reviewed at the weekly planning meeting. Lastly the nuclear shift supervisor (NSS) reviews the work scope and approves the work package for implementation.

The team found that the planning and conduct of PMs at power were not based on a deliberate documented methodology that assured a consistent net safety benefit. Standard planning elements did not include an assessment of the current system availability, operability and reliability of alternate safety systems, or the percentage of allowable outage time used by the PM/OST outage window. A lack of rigor in planning was observed in the incorporation of corrective maintenance into the PM/OST window, because administrative limits are not established to assure that increases in outage times are justified and appropriate for the maintenance planned. The justification to perform PMs/CMs at power was qualitatively based on a lack of equipment failures more so than an evaluation that balanced relative increases in equipment outage time to improved safety system performance.

The team also noted that management oversight of PMs at power was not commensurate with the potential risk associated with the voluntary removal of TS systems from service. The team observed that the same management reviews were conducted for both PMs at power and routine maintenance and surveillance. The lack of additional management oversight represented missed opportunities to assure that: (1) increases in safety system unavailability due to performing PMs at power are acceptable; (2) the conduct of PMs and CMs at power has resulted in improved system performance or reliability; and, (3) that the removal of safety systems from service was warranted by operational necessity and not by convenience.

In summary, the team concluded that the voluntary entry into TS action statements for maintenance and surveillance on safety systems was not consistently managed to assess the derived benefits gained from removing safety systems from service. Although no significant trends in safety system unavailability were observed, the team was concerned that potential risks or safety benefits gained from performing PMs at power were unavailable for licensee assessment. The above program observations were discussed in detail with maintenance management. Additional station management attention is warranted in this area.

2.2.4 Maintenance Trending

2.2.4.1 Maintenance Backlog

The corrective and preventive maintenance backlogs were managed within pre-established goals. Total backlogs, percentage older than three months and able to work, and items deferred to the next outage are trended and presented monthly for management review. A detailed review of the electrical backlog confirmed that there was no outstanding maintenance potentially affecting the operability of safety systems. Although team review of the 1992 through 1994 backlogs identified no adverse trends, the PM backlog did show a relatively steady increase through 1993. This trend was also recognized by station management and even though the total was less than the station goal, corrective actions were implemented to better manage these outstanding PMs.

2.2.4.2 Equipment Trending

A number of programs are used by the licensee to trend equipment failures and work backlogs. Annually, the station performs a Preventive Maintenance Program Review (PMPR) to assess the effectiveness of the PM program. This program review is conducted in accordance with Maintenance Manual Section 4.9, "Preventive Maintenance Program." The PMs performed are reviewed against elements that include PM frequency, equipment operational history, and procedural requirements. Bases are provided for the addition, deletion, and modification of PM requirements. The team noted that the quality of the PMPR improved over the last two years because justifications for PM program changes were more succinct and of better technical detail. The PMPR also evaluated potential changes to the program resulting from the implementation of future design changes.

The Operations Department generates and distributes a Monthly Plant Summary (MPS) that provides a good assessment of operating conditions and maintenance activities. Work scope and time requirements, coordination activities, reportability evaluations, and compensatory measures are appropriately described for management review. Further, the MPS documents the plant conditions required for the conduct of maintenance and lists the out of service time caused by specific maintenance on TS equipment and systems. Notwithstanding, the team found that availability trending was lacking because the licensee does not assess the "cumulative" out of service time for TS equipment. The team considers cumulative availability a meaningful indicator of system reliability. Further, excessive unavailability could potentially indicate excessive entries into TS action statements for preventive or corrective maintenance. The licensee performs some system availability trending via the monthly Trend Monitoring Report, however: (1) availability was trended for only three safety systems (safety injection, Class 1E power, and high head injection); (2) the report truncated all availability information from the 1993 operational cycle; and, (3) the trends did not include the time generated by the voluntary entrance into TS action statements for preventive maintenance. Based on the data reviewed, the team concluded that the breadth of system availability information did not significantly lend to a comprehensive assessment of the effect of preventive and corrective maintenance on the availability of TS systems. The maintenance staff stated that this area was currently evaluated in response to the NRC maintenance rule.

2.2.5 Engineering Assessment of Equipment Performance

System Engineering was implemented in early 1993 as part of an organization change made, in part, to improve overall effectiveness. Responsibilities and program requirements are contained in administrative procedure MPUAM, Section 2.4, "Maintenance Engineering and Assessment Department." The team reviewed selected aspects of Systems Engineering assessments of equipment performance and degraded conditions to determine the effectiveness of this program.

2.2.5.1 Identification of Equipment Deficiencies

Systems Engineering personnel conduct walkdowns of safety and non-safety related systems to periodically evaluate system performance, structural integrity, and area conditions. The walkdown program was implemented in early 1993 as described in MPUAM, Section 8.2.1, "System Walkdowns." Herein, cognizant engineers are required to assess housekeeping, fire protection, industrial safety, radiation protection, and material conditions in their areas of expertise.

The team concluded that the program appears to be a good initiative and reasonably effective. Since program inception, approximately 70 percent of the safety systems have been inspected by System Engineers. A sampling of inspection results indicated that procedural requirements were met, and that deficient conditions were identified and corrected. However, the team observed that the results tended to parallel activities already performed by plant operators, inservice testing, and supervisory housekeeping tours. The team discussed these observations with the cognizant engineering supervisor who acknowledged that a more robust program would critically evaluate the conditions observed from an engineering point of view.

2.2.5.2 Evaluation of Deficient Conditions

The engineering staff evaluation of potentially deficient material conditions, identified by the team during system walkdowns, was of mixed quality. For example: a degraded condition common to all three high head safety injection RW cooling lines was not initially evaluated for torsional stress considerations; an initial evaluation conducted to assess a deflected gage pointer on a safety system was observed to be non-conservative by the team and required further evaluation by the station. Thorough evaluations were performed for observations involving fire protection, environmental and design qualification of gasketing, and potential seismic concerns. The conditions identified above were not adverse to safety system operability; however, they demonstrated that the rigor applied to engineering of identified deficiencies varied noticeably.

2.2.5.3 Basis for Continued Operation

A Basis for Continued Operation (BCO) documents the licensee's determination that continued plant operation with a degraded or nonconforming condition affecting a structure, system, or component (SSC) is allowed within the plant license and design basis. The BCO process is controlled by Administrative Procedure NPDAP 5.2, "Preparation of Problem Reports, Conduct of Critiques and Followup Actions." The team reviewed approximately five percent of the total number of BCOs written during 1993 and 1994 and split this sample size between Unit 1 and Unit 2.

The team found that the BCO process generally follows the guidance provided in Generic Letter 91-18, which references NRC Inspection Manual, Part 9900, "Resolution of Degraded and Nonconforming Conditions." Attachment 13 to NPDAP 5.2 established a BCO format intended to assure that degraded conditions are properly and consistently documented. Questions are pre-established to develop a methodical assessment of overall risk. The program considers the availability of redundant equipment and systems, and identifies compensatory measures (such as administrative controls) to provide reasonable assurance that safe plant operation is possible with the degraded condition. This determination is augmented by analysis of design conservatisms, probability of needing the safety function, and the resulting effect on the total core damage frequency. Quantification of risk was based on the Individual Plant Examination (IPE).

The team found that several aspects of the station BCO process departed from NRC guidance. First, NRC Manual Chapter, Part 9900, envisions that operability decisions be made immediately or within 24 hours based on safety significance The BCO program allows for a period greater than 24 hours and does not assess the timeliness of the operability determination based on safety significance. This lack of time management allows uncontrolled delays when operability and engineering reviews are required. An example illustrating an untimely review involved an evaluation of degraded RTD insulation that potentially effected the operability of some reactor trips and control functions. This condition was identified on October 4, 1993, and the BCO was completed on October 7.

The second aspect involved the determination of "operability" for systems found degraded or nonconforming. The BCO program allows an indeterminate state of operability. This state is not recognized by the NRC guidance, because operability must be predicated on reasonable expectation that the SSC is either operable or inoperable. In the absence of reasonable expectation, the SSC should be declared inoperable to assure that license requirements and corrective actions are timely. An example, in which the station delayed an operability determination was Problem Report 2-93-023. This report documented an overfill condition of the hydraulic reservoirs for valves used to vent the steam generators. There are no TS action statements associated with these valves, however, the degraded condition represented a potential safety concern because the valves are credited to minimize core damage during certain accident situations. The valves were repaired in a timely manner.

Thirdly, the team found that the justifications performed to determine whether continued plant operation would be safe with a degraded condition were inconsistently documented and generally did not assess the acceptability of operating with a degraded condition for the duration of the BCO. A number of BCOs did not assess the effects of subsequent testing, other equipment failures, or changes in plant operating conditions. For example, when the licensee identified that the discharge isolation valve for the "C" RW pump did not shut as designed (PR 1-93-127), a documented assessment was not conducted to evaluate the leak integrity of the pump discharge check valve. This was important to assure continued RW system operability because failure of the check valve to seat would result in flow bypass and a reduction in RW heat removal capability to safety systems. A second example involved BCOs developed to justify continued operation of MOVs with thrust and torque values above allowable, yet below yield limits. The BCOs did not consistently evaluate weak-link analyses or assess the effect of subsequent valve testing during periodic surveillance testing. A third example involved the continued operation of containment isolation valves (within containment) that were constantly being wet down due to water leakage from a different system (PR 2-93-028). The licensee determined that the subject valves were environmentally qualified (EQ), however, an assessment was not performed to determine whether the "wet" environmental condition was enveloped by the 40-year normal plant and 1-year post-accident EQ assumptions. The team determined that the water leak was repaired during the past refueling outage and that an engineering review was in progress at the completion of the team's on site inspection.

The team also found that the BCO program does not include a periodic assessment of the degraded condition nor does it trigger increased management involvement based on the safety importance of the degraded component. The lack of program rigor in this area represented a potential concern because the licensee routinely justifies plant operation with degraded components for extended periods of time to allow repair during the next scheduled refueling outage. As a result, the licensee was vulnerable to plant and equipment conditions that potentially invalidated original BCO justifications. These conditions include subsequent reactor mode changes, equipment failures, and deviations in system lineups. Although the team did not identify any safety concerns, improved program control in this area would provide additional assurance that BCO assumptions remain valid for the entire BCO period.

Lastly, the team determined that, in general, when BCOs involved EQ, seismicity, and inservice testing (IST) concerns, inconsistencies were observed in the determination of safety significance, and whether the condition was in conformance with design and license requirements. Inconsistency in determining safety significance was demonstrated when two different BCOs were written on the same component resulting in two different determinations of safety significance. In addition, in some cases safety significance was based on the design function of the degraded component; in others, it was based on the design function of the system containing the component. Problem Report 2-93-001 documented that the stroke time of a steam generator blowdown isolation valve exceeded the IST limit, based on an UFSAR value for high energy line break and EQ considerations. An appropriate evaluation was conducted to provide reasonable assurance that continued operation was safe, however, the licensee considered that operation in this manner was within its licensed basis. Subsequent to the initial assessment, a 10 CFR 50.59 safety evaluation was performed to assure that an unreviewed safety question did not exist and that a change in the TS was not required. Licensee management acknowledged that inconsistencies have occurred and plans to conduct additional training.

Overall, the team did not identify any BCOs that reached inappropriate conclusions. However, the BCOs reviewed were inconsistently documented, generally did not assess for operating with the degraded condition for the duration of the BCO, and did not closely follow the guidance of Generic Letter 91-18. The licensee stated that the deficiencies noted above were addressed by a recent revision (Revision 3) to NPDAP 5.2. The team reviewed the revised procedure and determined that the procedure provided enhancements in the areas of concern. The effectiveness of implementation of the revised procedure was not evaluated by the team. The team was also concerned that the current outstanding BCOs would not meet the revised procedure requirements. The licensee stated that a review will be conducted to upgrade the current open BCOs, if required.

2.2.5.4 Inservice Testing

The team reviewed the 1993 Inservice Testing (IST) trend reports for both pumps and valves. The team concluded that the engineering assessment of IST data identified degrading equipment performance prior to failure and contributed to improved reliability of plant equipment and systems. This was consistently demonstrated for valve stroke times, valve leakage rates, and pump vibration monitoring on safety related components. Based upon the examples reviewed, vendor communications occurred, MWOs were written to correct the degrading conditions, and evaluations were generally conducted to review the significance of the degradation. The team found that IST open items and recommendations to improve component performance were effectively tracked because commitments, responsibilities, and estimated completion dates were assigned and managed. This list had relatively few outstanding items and narratives described expected improvements in component performance.

2.2.5.5 Lubrication Analysis Program

The team reviewed the implementation of the lubrication analysis program. Program requirements were performed in accordance with MPUAM, Section 8.3.2, "Lubrication Program" and samples were analyzed to assess equipment degradation. The analysis program includes both safety and non-safety equipment and totals more than 150 components. Sampling frequencies generally corresponded to vendor recommendations and the cognizant engineer articulated valid reasons for a sampling of PMs that did not. The strategy for oil sampling was graduated to increase sampling frequency and to conduct alternate analytical techniques (particulate, ferrographic, and spectrometric). This was considered a program strength. The cognizant engineer was knowledgeable of program requirements and acceptance criteria. Abnormal conditions were identified during periodic oil sampling.

2.2.5.6 Support to Plant Activities

The engineering support to plant maintenance and surveillance was good. Routine surveillance and work orders are reviewed by engineers within the maintenance department. Significant component failures are trended and documented in the periodic System Engineering Status Report. The specific failures and system problems are appropriately described and corrective actions clearly defined in the status report. The extent of coordination between the maintenance and engineering departments was on an as-required basis, based on the importance of the issue, complexity of system testing, or as directed during daily planning meetings. Good coordination and problem resolution for issues involving IST and motor operated valve testing were observed. One coordination difficulty was observed during this inspection period involving the communication of technical information to plant management. This occurrence involved the type of material found in the RW/lubrication oil heat exchanger for a high head safety injection pump. Nonetheless, good coordination was observed during investigation, corrective maintenance, and post-maintenance testing conducted for this issue. Ownership of safety systems was demonstrated.

2.2.6 Maintenance Procedures

The team reviewed selected maintenance procedures and concluded that instructions contained adequate detail, appropriate management controls, and provided additional assurance that maintenance would be of high quality. Procedures governing the planning of maintenance and surveillance provided good detail for the development of work packages. As delineated in Administrative Procedure NGAP 7.5, "The Maintenance Work Request," planning elements included design considerations such as seismicity, environmental qualification, and fire protection. Post-maintenance testing (PMT) was required to be pre-planned. PMT results are reviewed by the control room staff and the maintenance supervisor. Based on the maintenance and surveillance tests observed (reference Section 2.2.7), acceptance criteria were pre-established; initial corrective action proceduralized; and double verification of critical steps was routinely required. Maintenance procedures included some level of quality control such as independent verification and inspection. Procedure critique forms were integral to the procedures. Based on interviews, station personnel were cognizant of this procedure improvement process. The administrative procedures for the IST and lubrication oil analysis program also contained requirements for independent assessment and management reviews.

2.2.6.1 Deferral of Post-Maintenance Testing

The licensee allows PMT to be waived or delayed, based on guidelines established within NGAP 7.5. Acceptable reasons for delay included inability to establish acceptable plant or system operating conditions, or the generation of system inoperabilities or challenges caused by the PMT. For example, following the packing adjustment of a gage isolation valve for a safety system pressure transducer, the PMT to perform valve cycling could be delayed to keep the transducer in service. The team reviewed the outstanding PMT lists, discussed the status of Unit 1 items with a cognizant NSS, and concluded that the outstanding PMTs did not challenge the operability of safety systems. The team also determined that the documented PMT waivers provided adequate justification for deferring the PMT.

2.2.7 Maintenance and Surveillance Observations

The team conducted performance-based inspections of the maintenance and surveillance activities listed below. Procedures and work packages were reviewed for technical detail. Maintenance personnel were interviewed to assess knowledge and their commitment to quality maintenance. Components removed from service were inspected to assess material condition. The team verified that the activities observed were performed in accordance with Administrative Procedure NGAP 7.5, and Maintenance Manual Section 4.1, "Work Order Control," and Section 4.16, "Performance of Maintenance Procedures."

- Corrective Maintenance, MWR 28158 & 28160, River Water Heat Exchanger Debris Clogging, CH-E-7B

- Corrective Maintenance, MWR 27113, Solenoid Operated Valve Leakage, 2PAS-SOV-100

- Preventive Maintenance, procedure 1/2PMP-36NNS/SSBKR-1E, Station Black-Out Cross Tie Breaker Inspection, 4KVS-2A2

- Surveillance Test, OST 1.43.1, Area and Process Monitor's Channel Functional Check

Field observations of maintenance verified that personnel were knowledgeable of procedural requirements and system design. Work and surveillance packages were well planned. Work packages were of adequate detail to perform the designated tasks; drawings and vendor manuals were included to augment the knowledge and skills demonstrated by maintenance personnel. Good coordination was observed between plant departments, and activities were discussed at the daily planning meeting. Engineering and supervisory oversight was effective.

2.2.7.1 Clogging of the "B" HHSI Pump Heat Exchanger

Quarterly Surveillance BVT 1.30.3, "Heat Exchanger Performance Monitoring," identified that RW flow through the "B" HHSI (RW to lubrication oil) heat exchanger of Unit 1 was unacceptably low. The "B" HHSI train was administratively declared inoperable and Problem Report 1-94-47 was initiated. The investigation revealed that the first and third passes of the four pass heat exchanger was partially blocked with grasses, broken clam shells (pieces were smaller than a dime), and small twigs (1/8" diameter and 1/2" long). This caused flow to degrade to 7.3 gpm, below the acceptance criteria of 20 gpm. Normal RW flows typically range from 55 to 75 gpm representing a healthy margin to an unacceptable heat transfer rate. The "A" and "C" heat exchanger flows were adequate and indicated no adverse trend. Similarly, an engineering evaluation of other potentially effected components (most notably, control room air conditioning) identified acceptable heat exchanger performance and no degrading conditions. The Unit 2 HHSI heat exchangers also indicated good performance. The two upstream RW strainers were inspected and found in good material condition having collected approximately one cup of broken clam shells in the cone of the Y-type strainer.

Overall, an appropriate and timely review of debris effects on downstream components was conducted. Good communications to control room operators were observed regarding the satisfactory completion of surveillance and post maintenance testing. System Engineering personnel was actively involved and contributed to the restoration of this safety system. The identification of flow degradation demonstrated the effectiveness of the heat exchanger monitoring program. However, the team found that the root cause determination did not identify why the type and quantity of debris found in the RW strainers and HHSI heat exchanger differed in type and quantity. The licensee found only broken clam shells in the RW strainer; however, clam shells, grass, and relatively large twigs were captivated by the HHSI heat exchanger. These dissimilar findings indicated that a potentially different transport mechanism existed. Subsequent to the team's onsite inspection, the licensee determined that debris transport was caused by system configuration changes conducted during the last refueling outage.

2.2.7.2 Solenoid Operated Valve (SOV) Maintenance

The team observed corrective maintenance on post accident sampling valve 2PAS-SOV-100A and observed mixed performance. For example, prior to the cut to remove the deficient SOV, the maintenance crew demonstrated an excellent questioning attitude. They identified a potential concern regarding hydrogen gas entrapment within the system piping, which provides for a primary coolant hot leg sample. The work package documented that the system configuration prevented an effective venting arrangement. However, it did not completely assess the potential personnel safety issue or how to preclude the hydrogen concern. The implementation of lifted leads and jumpers controls to disconnect solenoid power and position indication wiring met procedural requirements. However, the of the actions performed on the lifted leads and jumper controls sheet was not clearly specify one of the leads lifted. This was acknowledged by the technicians, who stated that the documentation would be clarified.

2.2.7.3 Station Blackout Cross Tie Breaker Inspection

The team inspected the station blackout cross tie breaker (4KVS-2A2) while it was racked-out for preventive maintenance. Cleanliness of main and auxiliary contacts, spring alignments, and relay wiring represented good overall material condition. Similarly good conditions were observed in the breaker cubical. The team also observed the conduct of a performance-based QA inspection and concluded that this effort resulted in additional assurance that the maintenance would be of high quality.

2.2.7.4 Surv-'llance of Radiation Instruments

Surveillance test OST .43.1 identified that the "High Alarm" function of the fuel building ventilation exhaust radiation monitor failed to actuate a control room annunciator (A4-71) and the sequence events recorder. The subject instrument, RM-1VS-103B, is required by TS and is part of an engineered safety feature that isolates the fuel building on high airborne radiation conditions. The instrument was administratively declared inoperable and the balance of the surveillance was completed.

The team observed that the troubleshooting conducted by the control room operators was not of an equivalent management rigor or control as troubleshooting performed by the station maintenance department. Specifically, a relay thought to be at fault was pressed into its socket and then subsequently pulled-out to assist in troubleshooting. However, lifted leads and jumper controls were not implemented. In addition, multiple tests (performed to verify the failed condition) were not documented. These troubleshooting actions changed the as-found condition of the relay.

The team reviewed NRC Regulation Guide 1.33, "Quality Assurance Program Requirements (Operation)"; NPDAP 7.4, "Temporary Modifications;" and, Administrative Procedure 1/2.48.1, "Conduct of Operations." Regulatory guidance was accurately incorporated into plant procedures. Discussions with the control room operators confirmed that they had excellent knowledge of the system design and safety function. The NSS was involved with the troubleshooting and a MWO was written. However, the team concluded that the removal of the relay represented a lifted lead requiring independent verification and quality documentation. Station management acknowledged that proper administrative controls were not fully implemented during this troubleshooting.

The failure to implement established administrative controls during troubleshooting of the fuel building ventilation exhaust radiation monitor was of minor safety consequence. The team determined that appropriate corrective actions to enhance operator awareness of the procedural requirement were appropriate. Consequently, the criteria of 10 CFR 2, Appendix C, NRC Enforcement Policy, Section VII.B has been satisfied and this violation is not cited.

2.2.8 Conclusions

The team concluded that the maintenance program was adequately organized, and maintenance planning was effective through the use of daily schedules and meetings held with appropriate management involvement, good coordination of actions to correct emergent and multi-disciplined issues, and appropriate review of routine maintenance and surveillance testing activities. However, voluntary entry into TS action statements for maintenance and surveillance on safety systems was not consistently managed to assess the net safety benefit from removing safety systems from service. In the maintenance work backlog area, the team found that backlogs were managed within established goals, and actions were in progress to better manage the PM backlog and to reassess the priorities assigned to outstanding items. Trending of equipment failures and out-of-service times for safety systems was adequate. However, some trend assessments varied in analytical rigor and did not lend easily to an effective management format. Additionally, although no safety concerns were identified with the operability evaluations provided in the BCOs, weaknesses were observed in the management and implementation of the BCO program, resulting in inconsistent justifications, limited assessments of safety significance, and lack of documentation rigor. The weaknesses in the BCO program had been identified by the licensee, and corrective actions were recently implemented. Maintenance procedures were found to provide good detail and included proper management reviews, acceptance criteria, and a mechanism to elicit procedure improvement suggestions. Field observations of maintenance verified that personnel were knowledgeable of activities performed. The team concluded that engineering and supervisory oversight contributed to quality maintenance.

2.3 Problem Identification and Resolution

The team reviewed the licensee's programs and procedures designed to identify, assess, and resolve plant deficiencies and personnel performance issues. In addition to detailed documentation reviews, the team conducted a walk down of various accessible areas in both units to assess material condition and usage of problem identification mechanisms, interviewed selected station staff members, and observed various routine activities on site.

2.3.1 Problem Identification

The team found that, in general, the programs and processes for identifying plant deficiencies were appropriately structured and were being effectively implemented. Numerous mechanisms are available for reporting plant problems, issues, or performance concerns.

Based on a review of selected areas, the threshold for entering problems, issues, or concerns into these programs was appropriate. Tracking systems designed to assure management follow-up and resolution of the identified item were also found to be appropriately implemented.

The team reviewed the problem reporting program and its implementation as defined by NGAP 5.2, "Preparation of Problem Reports, Conduct of Critiques and Followup Actions." The program was determined to be well structured, understood by station personnel, and well maintained by the Shift Technical Advisor (STA) staff. The team noted that corrective actions identified in the Problem Reports (PRs), if not completed upon closure of the report, were identified on an open item tracking system for follow-up and verification of completion by the STAs. The team found the backlog of open PRs and follow-up open items to be relatively small, manageable, and monitored daily by station management. The team took a random and selected sampling of PRs and found them to have clearly defined the event or problem, which caused the PR to be written. Evaluation of the problems was generally thorough and resolutions appropriate. Follow-up open items were being closed in a timely manner.

Plant housekeeping and material condition tours by station management are governed by NGAP 8.8, "Plant Inspection Program." The team conducted plant walkthroughs to assess housekeeping and material condition (reference Section 2.2 of this report) and then compared those observations with the NGAP 8.8 findings. In areas where the Plant Inspection Program had been implemented by the licensee, the team found generally good agreement, with a few exceptions, between their observations and those identified via the Plant Inspection Program. The team noted a sizeable backlog of open deficiencies (principally material condition items) from a sampling of Unit 1 areas indicating that the threshold for identification of material condition items appeared appropriate, but follow-up corrective actions were slow. However, the team learned that a recent assessment by the Quality Services Department and a third party audit, identified that a number of deficiencies have been overlooked by this program and that an increasing number of planned plant inspections have not been performed as scheduled. These findings prompted station management to perform an NGAP 8.8 effectiveness review and to assign station supervisors responsibility for the housekeeping in specified areas of both units (reference Site Maintenance Department Memorandum ND3SMD:1659, dated February 28, 1994).

The team assessed the effectiveness review methodology and results and concluded that the review was both candid and critical. The identification of the Plant Inspection Program's shortcomings and the initiatives taken to address them were considered positive. Corrective actions to improve or replace the inspection program were not developed at the time of the team's onsite inspection and the effectiveness of the new zone responsible supervisor program was not assessed.

The Maintenance, Engineering and Assessment Department (MEAD) maintenance history review/trending program was good. The maintenance history review consists of a 15-month trend of components (by model number) which experienced four or more failures and an industry component failure analysis report (CFAR) which uses a three failures in 18 months screening criteria. The team reviewed the Unit 1 maintenance history review/trending summary and individual component corrective action plans, dated November 29, 1993, and December 16, 1993, respectively, and discussed the program implementation and selected component action plans with the responsible maintenance engineers. The team concluded that the trending and corrective actions were appropriate for those components reviewed and that there was appropriate involvement in the review process by the various disciplines on site. A management steering committee oversees the program implementation. The team noted that action plan items developed from the Maintenance History Review are entered into the MEAD commitment tracking system for appropriate followup and closure.

Between 1988 and 1991 the plant staff conducted safety system functional evaluations (SSFEs) to identify deficiencies or areas for improvement on eight different systems at Unit 1. As a result, 416 observation items were initiated to resolve the identified deficiency or make system improvements. As of January 7, 1994, 80 items remain open from the original 416 items. The team selected a sampling of closed and open items to assess the overall thoroughness of the evaluations, the adequacy of resolution, and the timeliness of closure. A detailed examination of eight observations and supporting documentation identified that the depth and detail of the SSFE efforts were excellent. The corrective actions and timeliness of resolution were appropriate. Lastly, the auditability and completeness of the individual observation item packages were excellent. Periodic reviews and trending by the SSFE management overview committee (MOC) were evident and appeared to be beneficial in bringing the remaining items to closure.

During team tours of Unit 1, the team noted that several hundred red deficiency tags were hung from the electrical power and control cables throughout the plant. Followup by the team determined that approximately 890 minor deficiencies (labeling and cosmetic type items) remain to be resolved from a total of approximately 4,000 items identified during a detailed electrical cable separation walkdown conducted by the station staff in the late 1980's. The resolution of these minor deficiencies has been identified under one maintenance work request (MWR 025674) which has been assigned a priority four (lowest priority category for maintenance work) for resource allocation and closure. The Construction Services Department plans to complete this work as resources become available. The team concluded that the action taken and planned to resolve these deficiencies was commensurate with their safety significance.

The team reviewed selected Quality Services deficiency reports (DRs) and corrective action reports (CARs) to assess the effectiveness of these mechanisms in identifying and resolving station problems. The team found the DRs and CARs were clearly written and the corrective actions appropriate for the deficiency identified. Timeliness of DR and CAR closure was adequate and the status of open Quality Services findings was periodically provided to line management for their information and action. The team noted that escalation of late responses or escalation of repeat findings was appropriate. Additional team observations involving the Quality Services programs are documented in Sections 2.1.8.4 and 2.4.1 of this report.

The team reviewed selected post-trip review reports and determined that they provided a detailed examination of the reactor trips. Causal analyses were generally thorough and well documented. In addition, the post-trip review package included a comprehensive examination of the computer generated pre- and post-trip data and corrective actions taken to correct or improve the data collection, as necessary. Identification of deficiencies or problems via the station post-trip review process was good.

2.3.2 Root Cause Analyses

The team noted that the root causes analyses performed by the responsible station groups follow generally accepted industry practices, with one exception. The detailed root cause analysis for events resulting from personnel error is performed only when specifically directed by station management. Based upon a review of Independent Safety Evaluation Group (ISEG) root cause analyses and problem reports (PRs) resulting in 10 CFR 50.73 Licensee Event Reports (LERs), the team concluded that a cursory root cause analysis is performed for the majority of the personnel error related events. This area was considered a weakness for the reasons described below.

The team determined that for the vast majority of the events, the Shift Technical Administrator (STA) staff performs the root cause analysis in conjunction with processing the associated problem reports in accordance with NGAP 5.2. Causal analyses are conducted by the maintenance engineering staff (systems and component engineers) per Technical Services Department Administrative Procedure TSAP 2.6, "Root Cause Analysis," and by the ISEG per the Nuclear Safety Administration Manual. Discussion with the STA staff identified that they all have received formal training in the various root cause analysis methodologies defined in NGAP 5.2. A review of selected PRs and LERs identified that all these methodologies have been applied in varying degrees.

Based upon documented information in the PRs, the team was in general agreement with a majority of the causal analyses performed by the STAs. However, review of selected PRs and all LERs for both units written in 1992 and 1993 identified that the root cause analysis for events resulting from personnel error were seldom of sufficient depth to understand the specific cause of the personnel error. Consequently, the adequacy of the corrective actions to address these personnel error related events was difficult to assess. LERs in this category were: 1-93-06, 1-93-09, 2-93-10, 2-93-11, 1-93-14, 2-92-03, 2-92-06, 2-92-07 and 2-92-12. The events described in these LERs were principally attributed to personnel error, however, no further analysis of this root cause was stated.

The team determined that detailed human performance root cause analyses are conducted by the STAs using the Institute of Nuclear Power Operations (INPO) Human Performance Enhancement System (HPES) techniques. A total of eleven HPES reviews were done in 1993 and only two conducted in 1994. Only a few of these human performance reviews were done to support a LER. The team discussed this observation with station management and learned that the performance of detailed HPES reviews by the STA staff is controlled by station management, due to resource and manpower limitations. The team determined that the STA staff currently consists of five STAs on rotating shift and a supervisor. A class of engineers is currently in STA training and should provide some staffing relief in the near term.

A review of documentation supporting the Unit 1 LER 93-13, Reactor Trip and Dual Loss of Offsite Power, dated November 11, 1993, identified that the human performance root cause analysis for this event was performed by the ISEG (reference memo NDISEG:0795, dated October 28, 1993). However, the ISEG root cause methodology, as defined in Nuclear Safety Administrative Manual, Volume IV, Chapter 4, Independent Safety Evaluation Group Root Cause Analysis Guidelines, abbreviates a detailed analysis of human performance root causes. The team determined that no detailed human performance analysis was assigned by station management for this event. Based upon the human performance causal analysis reviewed by the team, this analysis lacked sufficient depth and detail to clearly understand the personnel errors, which caused the event.

The team reviewed the corrective actions outlined in LER 93-13 and considered them to be of insufficient detail. The interim administrative switchyard controls (reference corrective action No. 2 and memo ND3MNO:3496, dated October 25, 1993) were found to be adequate. Long-term corrective actions were still being developed Additional station management attention is warranted for this event to ensure the personnel errors are clearly understood and that the corrective actions correspond to their respective root causes.

The team reviewed the root cause evaluation prepared in support of Unit 2 LER 93-14, Required Shutdown due to Inoperable Steam Driven Auxiliary Feedwater Pump, dated December 29, 1993, and Supplement 1, dated January 28, 1994, and identified a similar deficiency in the depth and detail of the root cause analysis for the system failures. Specifically, no detailed root cause analysis was performed for the failure of 2MSS*SOV105A or 2MSS*SOV105D and no detailed root cause analysis was performed for the installation of an improperly sized buffer spring in the governor valve. The PR root cause analysis was prepared by the maintenance engineering staff and was considered by the team to be a summary document of the troubleshooting efforts taken to identify the hardware failure mechanisms and not a root cause of the failures. Review of the LER 93-14 corrective actions indicated that the immediate actions to correct the obvious component failures were addressed, but the actions to prevent recurrence were still pending. Additional station management attention is warranted to ensure appropriate corrective actions to prevent recurrence are addressed for the specific personnel errors causing these system failures.

Team review of Unit 2 LER 93-012, Emergency Diesel Generator Sequence Circuit Deficiencies, dated December 6, 1993, and the supporting root cause analysis (NDISEG:0804, dated December 6, 1993), found the analysis to be significantly limited in scope. Specifically, the root cause evaluation did not identify that the engineering specifications that prescribed the qualification tests for the new solid state timers was deficient because it did not specify the actual operating conditions to which the timer/relay contacts would be subjected in service (see Section 2.1.8.1 of this report). In addition, the commercial grade dedication process did not identify appropriate pre- and post-installation tests. The root cause evaluation did identify that inadequate design understanding and, therefore, appropriate pre- and post-installation testing was not performed, but this was more a secondary cause and not the primary cause. Notwithstanding, a corrective action was targeted in the LER, which should address the procurement specification deficiencies. The team concluded that additional management attention is warranted for this event to ensure that engineering specifications are properly developed and translated into procurement documentation.

A selected sampling of recent ISEG root cause analyses identified that the analyses were generally well conducted and thorough, with the exception that human performance related root causes were not examined in detail. The team found that recommendations developed from the ISEG root cause evaluations were only made if the recommendation (corrective action) did not duplicate a corrective action already known or identified to the ISEG as being addressed by the station staff. The team found this practice awkward from an auditability standpoint (inability to easily identify a one-for-one root cause and corrective action), but not a programmatic concern. Lastly, the team noted that ISEG maintained an excellent record of their root cause recommendations. Followup for completion and effectiveness of the recommendation was performed by the responsible ISEG engineer.

Team review of recent Operations Experience Group (OEG) Trend Reports (October 1992 to February 1993, January 1993 to July 1993, and January 1993 to December 1993) identified that these trend reports are concisely written and thorough. However, the team noted that the adverse trends identified by the OEG are not identified in any existing problem identification programs, or in the trend reports themselves, for specific followup and corrective action. Station management acknowledged this program shortcoming and indicated that action would be taken to address it. Further discussions with station management identified that two specific management level task forces (radiation barrier task force and human performance task force) were developed at the request of the Operations Experience Subcommittee (OES) in response to adverse performance trends. The OES is a subcommittee of the Offsite Review Committee (ORC) and per their charter, reviews the OEG Trend Reports.

The team determined that the human performance task force is a recent initiative developed in response to the increasing trend in human performance related events. The task force initiatives, to date, are to assist in the development of departmental goals for limiting the number of personnel errors in the year and to assist in the development of self-checking programs tailored to each department's functional needs. The team viewed the human performance task force initiative as a positive step in addressing an adverse trend in overall station personnel performance, but was not able to assess its effectiveness, to date. The team did not review the radiation barrier task force efforts.

During the team's site visit an event involving the refueling bridge crane and fuel handling equipment occurred on March 2, 1994. Specifically, the bridge crane operator moved the bridge before raising the spent fuel handling tool. The tool was fortunately not latched with a fuel assembly, but the bridge was moved approximately 10 feet before the error was identified. The team verified that appropriate immediate actions were taken by the refuel floor staff and that a problem report and causal analysis was initiated. The human performance analysis and associated corrective actions were completed subsequent to the team's site visit, but were reviewed for adequacy. The team found the analysis to be thorough and sufficiently detailed. Corrective actions included procedural changes to ensure double verification of raising the spent fuel handling tool and increased emphasis on self-checking and pre-shift briefings. As discussed above, broader human performance improvement initiatives have also been taken. The team concluded that station staff response to this event was appropriate.

2.3.3 Corrective Actions

Based upon a collective review of the various mechanisms and processes discussed above and throughout this report, the corrective action programs and processes assessed were generally good. Few repeat problems were identified, with the exception of the station staff identified trend of an increase in personnel error related events. This trend indicates that actions taken, to date, have not been effective in reversing this adverse trend. As noted above, a recent station initiative (the human performance task force) was undertaken to address this issue. However, the lack of detailed human performance root cause analysis potentially results in ineffective corrective actions to prevent recurrence, as stated in the examples above, and warrants further management attention.

A Performance Review Team (PRT) was sanctioned by the Senior Vice President and Chief Nuclear Officer to conduct a broad scope review of Beaver Valley programs and management. The PRT conducted approximately 150 interviews of plant staff and assessed a broad spectrum of areas. The PRT identified findings in several areas, such as, management oversight, communications, and teamwork. Many of the findings of the PRT were collaborated by the OSTI during interviews with the Beaver Valley staff. The Beaver Valley staff interviewed stated that the PRT was a positive effort; however, many of the staff interviewed expressed apprehension with implementation of corrective actions. The licensee management was in the process of developing corrective actions for the PRT findings during this inspection. The team concluded that the timely implementation of these corrective actions is important to restore and maintain previous strong performance at Beaver Valley.

2.3.4 Conclusions

The team concluded that the various station programs to identify, assess, and resolve plant deficiencies and personnel performance issues were satisfactory. Problem identification was accomplished by a variety of mechanisms and the threshold for entering items into these various programs was appropriate. Root cause analysis for station events was adequate. The limited application of detailed causal analysis for personnel performance errors was considered a significant weakness and warrants management attention. The corrective action programs (tracking and closure) were considered good, however, the increasing trend in personnel performance errors indicates corrective actions taken, to date, have not been totally effective. Recent personnel performance improvement initiatives have been taken, but could not be assessed.

2.4 Self-Assessment/Oversight Programs

The team assessed the effectiveness of the licensee's self-assessment program for providing site and corporate management accurate and timely feedback on overall plant performance. The team evaluated the performance of the quality assurance program, onsite safety committee, offsite review committee, and independent safety evaluation group.

2.4.1 Quality Assurance Program

The team reviewed the licensee's quality services unit (QSU) organizational structure, interfaces with other plant and corporate organizations, role in assessment of plant performance and program effectiveness, and identification of deficiencies.

The team reviewed a number of site quality assurance (QA) audits to assess the scope, findings, and adequacy of the QSU audit program. The team reviewed audit reports prepared and issued during the past three years. Audit reports in the areas of corrective action, design change control, plant configuration, inspection, testing, plant performance, and the station inspection program were reviewed in detail. Additionally, QSU department surveillances, inspections, examinations, and assessments in the areas of operations, maintenance, radiation safety, and procurement were reviewed. Lastly, the administrative and implementing procedures for the QA program were reviewed and assessed.

The team determined that the audits were comprehensive, of good technical quality, and were well documented. For example, the audit of the station Design Control Program had good findings and presented clear assessments and recommendations. For this audit the team noted an extensive sample size of over 70 documents, including Technical Evaluation Reports, Engineering Specifications, Design Concepts, 10 CFR 50.59 Safety Evaluations, and Design Calculations. Most of these 70 documents were less than six months old and were reviewed by QSU to assess Nuclear Engineering Department (NED) activities relative to procedure compliance. Adverse findings identified in this audit included inadequate bases to support certain 10 CFR 50.59 changes due to a lack of adequate technical justification, and procedural weaknesses in the coordination of the design control program.

Two other noteworthy 1993 QSU audits reviewed by the team involved the review of station corrective action programs. Corrective action audits are performed twice per year to evaluate the adequacy and effectiveness of actions taken by the station to correct deficiencies identified via NRC inspection reports, Information Notices, Generic Letters, Bulletins, INPO Significant Operating Experience Reports, Licensee Event Reports, Incident Reports, plant performance data, maintenance history data, and Nuclear Plant Reliability Data. The first corrective action audit covered the first half of 1993. This audit did not identify any findings or observations indicative of programmatic weaknesses in the site corrective action programs. The second corrective action audit (reference ND3MQS:0703, dated December 30, 1993) identified several weaknesses including untimely corrective action implementation and review of industry events, failure to perform regular independent review by certain plant groups, and some specific examples of ineffective corrective action for identified problems or trends. The team noted that plant management acknowledged these programmatic deficiencies and had initiated actions for further investigation by means of a site-wide Performance Review Team (PRT). Consequently the resolution of the identified deficiencies presented in the December 30, 1993, audit report had been deferred until the PRT results and an action plan had been established.

The team determined that the QSU audit program and assessment processes were effective and provided management detailed feedback on the effectiveness of various station programs. The team found that the QSU staff was experienced and knowledgeable. As a result, the implementation of the QA program was effective in identifying plant deficiencies. The team noted that the QSU organization has been conducting performance-based assessments since March 1990. The team noted that a new system had been implemented by QSU to reassess previously identified deficiencies called the Audit Follow-up Report (AFR) system. This system assists QSU in verifying that corrective action has been properly implemented and that the original deficiencies have been resolved. The inspectors reviewed the AFR process and found the deficiencies were tracked efficiently and included future verification dates for rereview of corrective action implementation. Another recent QSU program enhancement was the addition of a standardized checklist for all 1994 audit plans for verifying corrective actions. This checklist captures essential questions to verify the adequacy of corrective action and references the applicable regulatory or procedural basis for the questions. The team determined this checklist was a good initiative by QSU, but was not able to assess its effectiveness due to its recent implementation.

The team noted effective communication and cooperation existed between the QSU staff and the other site departments. The team assessed the relationship of the site QSU organization with other site organizations during interviews with managers, supervisors, and plant staff. The team concluded that this relationship was strong and that managers expressed respect for the competence of the QSU organization. Requests for audits and assessments by individual departments was evident, demonstrating confidence in the QSU organization's abilities and quality of their findings. The team confirmed that the number of QSU audits performed exceeded the minimum technical specification requirements.

Based on team review of two Causal Factor, Root Cause, Trending Working Group (CRTWG) reports (generated by the QSU staff on an annual basis) and interviews with station personnel, the team determined that these reports were of limited self-assessment value. QSU management stated that they were cognizant of this weakness and had initiated action to improve the quality and effectiveness of the CRTWG reports. In a memoranda, dated December 14, 1993, the CRTWG report assessment and its 21 recommendations were documented for QSU management review. The team reviewed these recommendations and concluded that each of the recommendations was well supported, clearly presented, and provided useful information to improve the overall effectiveness of the CRTWG reports.

2.4.2 Onsite Safety Committee

The team reviewed the conduct of the Onsite Safety Committee (OSC) to verify that self critical, multi-disciplined reviews were being conducted of plant activities including determinations to ensure that no unreviewed safety questions result from changes made to the facility. Additionally, the team verified that technical specification requirements regarding the OSC were being satisfied.

The team attended the one regularly scheduled OSC meeting held during the team's on site inspection. The meeting included discussions regarding many procedural revisions, a field change, and a temporary modification. The team concluded that the presentations were satisfactory and that OSC reviews were adequate. A temporary modification presented regarding heat trace circuits' control scheme was tabled for further OSC review due to an inadequate supporting safety evaluation. The safety evaluation failed to present the original design basis for the heat trace circuits. The team viewed the tabling of this OSC review as appropriate. The team verified that the technical specification OSC quorum requirements were satisfied.

The team reviewed the OSC open item list, the frequency of OSC meetings conducted, and selected OSC meeting minutes held in the last six months. The team noted that the number of outstanding OSC commitments was low and the number of overdue commitments was low. The team noted that the frequency of OSC meetings exceeded minimum technical specification requirements. A review of previous OSC meeting minutes indicated that the OSC was addressing appropriate plant activities. The team concluded, based on observation of the meeting, review of documentation, and interview results, that the OSC satisfied technical specification requirements.

2.4.3 Offsite Review Committee

The Offsite Review Committee (ORC) is a technical advisory group, which performs independent reviews of plant activities. The ORC is required via their Charter and technical specifications to review, audit, evaluate, and make recommendations to the Senior Vice President, Nuclear Power Division. The ORC is composed primarily of senior licensee management personnel and is augmented by plant staff and outside consultants.

The team reviewed the ORC Open Item history file for items generated from May 1988 through January 1994. The team found that the resolution of open items was prompt, well focused, and clearly presented. At the time of this inspection only two ORC items remained open. Nuclear Safety Administrative Manual, Volume III, contained the ORC Charter and defines the responsibilities, authority, and requirements of ORC Subcommittees. The four ORC subcommittees are: Audits and Inspections; Health Physics and Chemistry; Operating Experience; and Maintenance and Engineering. Each subcommittee conducts independent reviews and reports their results to the ORC.

The team reviewed the minutes of selected ORC and subcommittee meetings held over the past six months to verify that technical specification requirements had been met with respect to the ORC composition, duties, responsibilities, and meeting frequencies. The team noted that the ORC has been meeting more frequently than the minimum requirement to meet once every six months. The team reviewed the backgrounds of the ORC members and concluded that the ORC members had broad and extensive experience in nuclear operations.

A deficiency was self-identified by the licensee where two ORC audits required to be performed annually by QSU for ORC had exceeded the 12 month audit cycle. Accordingly, the licensee initiated a Deficiency Report (QSAS-43) stipulating corrective action to prevent any future audits from exceeding their annual requirement. This corrective action included establishing more specific criteria for audit frequencies and revised QSU procedure 18.1, "Audit Schedules", accordingly. At the time of the team inspection the final disposition of DR QSAS-43 was pending, but both audits had been satisfactorily completed. The failure to conduct these audits within the prescribed frequency is a violation of NRC requirements. However, actions taken in response to this non-compliance were appropriate and timely and the event was of minor safety consequence. Accordingly, the criteria of 10 CFR 2, Appendix C, Section VII.B.2 of the Enforcement Policy has been satisfied and this violation is not cited.

The team concluded the ORC satisfied its technical specification requirements with the above exception and provided effective oversight of plant activities. The team determined that ORC reviews were sound and appropriate.

2.4.4 Independent Safety Evaluation Group

The team reviewed the Independent Safety Evaluation Group (ISEG) and their role in providing quality independent assessments and recommendations to improve the performance of station activities. Additionally, the team verified that technical specification requirements regarding ISEG were being satisfied.

The team reviewed ISEG Activity Summaries for December 1993 through February 1994 provided to the Vice President, Nuclear Group. ISEG activities during this time frame included root cause evaluations, independent monitoring of plant activities including outage shutdown safety system walkdowns, and trending of ISEG root cause evaluations. The team verified that ISEG did not provide line function responsibility. The team determined that evaluations conducted by ISEG were satisfactorily performed to assess areas for improving plant performance and that recommendations made were appropriate to correct identified deficiencies. The team concluded that the ISEG satisfied technical specification requirements.

2.4.5 Conclusions

The team concluded that QSU audits and surveillances of various plant activities were comprehensive, of good technical quality, and were well documented. The team determined that the QSU assessment processes and the QSU audit program were effective largely due an experienced and knowledgeable QSU staff. Recent QSU initiatives to verify corrective action implementation were determined by the team to be a good effort for assuring thorough reviews by the QSU. Reviews and assessments of plant activities by the GSC, ORC, and ISEG fulfilled and often exceeded minimum technical specification requirements. The team concluded that adequate measures had been established to provide effective oversight of plant activities.

2.5 Exit Meeting

The team met with those denoted in Appendix A on March 18, 1994, to discuss the inspectors' findings that are detailed in this report. The licensee did not take issue with any of the findings presented at the meeting.

APPENDIX A

PERSONS CONTACTED

Duquesne Light Company

* C. Bakken, Nuclear Shift Supervisor
* J. Baumler, Director, Audit and Surveillance
* E. Chatfield, General Manager, Nuclear Support Unit
* D. Dignan, Offsite Review Committee Coordinator
* A. Dulick, Operations Experience Manager
* S. Fenner, General Manager Maintenance Programs Unit
* L. Freeland, General Manager Nuclear Operations
* K. Halliday, Director, Electrical Engineering
* B. Harey, Director, Technical Training
* G. Kannerdeiner, Director, Materials and Standards Engineering
* F. Lipchick, Sr. Licensing Supervisor
* M. Mirchich, Acting Director, Procurement Engineering
* T. Noonan, Division VP Nuclear Operations and Plant Manager
* K. Ostrowski, Unit 1 Operations Manager
* M. Pavlick, Manager Maintenance Planning and Administrative Department
* J. Sasala, Director, Nuclear Communications
* G. Shildt, Supervisor System Engineering
* J. Sieber, Sr. VP and Chief Nuclear Officer
* M. Siegel, Manager Nuclear Engineering Services
* D. Szucs, Sr. Eng., Nuclear Safety Department
* N. Tonet, Manager, Nuclear Safety
* G. Thomas, Division VP Nuclear Services
* D. Williams, Sr. Licensing Supervisor
* K. Woessner, Sr. Engineer
* R. Zabowski, Director System Engineering

Nuclear Regulatory Commission (NRC)

* R. Blough, Acting Chief- Engineering Branch, DRS
* G. Edison, NRR Project Manager
* W. Lazarus, Chief, Projects Section 3B
* L. Rossbach, Senior Resident Inspector, Beaver Valley
* P. Sena, Resident Inspector, Beaver Valley

* Denotes attendance at the exit meeting held at the Beaver Valley Power Station, March 18, 1994.

Note: The list of DLC persons contacted does not include every individual contacted during this inspection. The key persons involved in the inspection are included in the list.