April 21, 2000

Mr. G. Rainey, President
PECO Nuclear
Nuclear Group Headquarters
Correspondence Control Desk
P. O. Box 195
Wayne, PA 19087-0195

SUBJECT: NRC INSPECTION REPORT 05000352/2000-001; 05000353/2000-001

Dear Mr. Rainey:

This letter transmits the NRC Engineering Team Inspection that was conducted at the Limerick Generating Station from February 7 to February 11, 2000, and from February 22 to February 25, 2000. The overall objective of the inspection was to determine whether engineering was providing support for safe plant operations. At the conclusion of the inspection on March 10, 2000, the preliminary inspection findings were discussed with your staff.

The inspection was directed toward areas important to public health and safety. We used NRC's existing inspection processes during this inspection. Future inspections will be conducted under NRC's revised reactor oversight program. The areas examined during this inspection included your engineering performance in plant modifications, technical issue identification and resolution, your corrective actions for resolving two previously identified inspection items, and 10 CFR 50.59 safety evaluations relating to changes, tests or experiments.

Overall, the team found that your engineering provided good support to plant operations and maintenance. Plant modifications designed by engineering were typically of good quality. Engineering usually conducted thorough investigations for the identified technical issues, and had initiated a good air-operated valve program. In addition, the team also found that your corrective actions for the June 1999 Unit 1 HPCI system failure were appropriate and had been completed in a timely manner. No additional supplemental inspection is required for this issue.

Based on the results of this inspection, the NRC determined that two Severity Level IV violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs) consistent with Section VII.B.1.a of the NRC Enforcement. The first NCV involved four examples of noncompliance with 10 CFR 50.55a, Codes and Standards, that pertained to the in-service test (IST) program at Limerick. The second NCV involved two examples of inadequate design controls: one for the development of the pump curves for the IST of the emergency service water pumps, and one for the set point of the high pressure coolant injection pump minimum flow. A detailed description for each of these violations is included in the enclosed report. If you contest any of these violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory

Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, Region I, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Limerick Generating Station.

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

Should you have any questions concerning this inspection, please do not hesitate to contact me.

Your cooperation with us in this matter is appreciated.

Sincerely,

/RA by Brian E. Holian for/

Wayne D. Lanning, Director
Division of Reactor Safety

Docket Nos. 05000352, 05000353

Enclosure: NRC Inspection Report 05000352; 05000353/2000-001

cc w/encl:
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REGION I

Docket Nos.	05000352, 05000353
License Nos.	NPF-39, NPF-85
Report No.	05000352/2000-001, 05000353/2000-001
Licensee:	PECO Energy Correspondence Control Desk P.O. Box 195 Wayne, PA 19087-0195
Facilities:	Limerick Generating Station, Units 1 and 2
Location:	Wayne, PA 19087-0195
Dates:	February 7 - 11, 2000, and February 22 - 25, 2000
Inspectors:	Leonard Cheung, Team Leader Suresh Chaudhary, Senior Reactor Inspector Leonard Cline, Reactor Inspector (Trainee) Joseph Colaccino, Mechanical Engineer, NRR (part time) Douglas Dempsey, Reactor Inspector Kenneth Kolaczyk, Reactor Inspector (part time) Alfred Lohmeier, Senior Reactor Inspector
Approved by:	William H. Ruland, Chief Electrical Branch Division of Reactor Safety

EXECUTIVE SUMMARY

Limerick Generating Station
NRC Inspection Report 05000352/2000-001, 05000353/2000-001

Introduction

An onsite engineering team inspection was conducted at the Limerick Generating Station from February 7 to February 11, 2000, and from February 22 to February 25, 2000. The overall objective of the inspection was to determine whether engineering was providing proper support for safe plant operations. The inspection also included the evaluation of the implementation of the 10 CFR 50.59 safety evaluation program relating to changes, tests or experiments at the plant, and your corrective actions in response to the June 1999 high pressure coolant injection (HPCI) system failure (a white performance indicator). The team consisted of four full-time inspectors, two part-time inspectors, and an inspector trainee.

Engineering

- Plant modifications at Limerick were designed and implemented in compliance with the NRC regulations. An adequate system was in place to ensure that affected drawings, procedures, and design documents were updated to reflect the modifications. Calculations, analyses, and output documents used appropriate codes and regulatory requirements as design inputs. Assumptions were technically reasonable and were appropriately documented. Design information between technical disciplines was used correctly.

  A 1989 modification incorrectly excluded a large number of ASME Code Class 2 and 3 relief valves from the IST program. (This was a non-cited violation of 10 CFR 50.55a). (Section E1.1)

- Temporary plant alterations (TPA) were properly designed and implemented. Engineering involvement in safety evaluation determinations was evident. Post-installation testing (where necessary) and modification tagging requirements were in accordance with the procedures. There were no long-standing TPAs. The licensee provided adequate controls for the installation and timely removal of TPAs. (Section E1.2)

- The emergency service water and high pressure coolant injection systems were capable of performing their design basis functions. The design bases and configurations of the ESW and HPCI systems were adequately controlled. However, several examples of noncompliance with 10 CFR 50.55a pertaining to in-service testing of components in these systems were identified. In addition, a violation involving two examples of inadequate design controls was also identified. These deficiencies were entered into the licensee’s corrective action program and were being treated as non-cited violations. (Section E1.3)

- The Engineering Response Team concept supported engineering's timely response to routine technical problems and emerging plant issues. Engineering support to maintenance in resolving maintenance problems and implementing the maintenance rule was satisfactory. The licensee usually conducted thorough investigations for the identified technical issues. The air-operated valve program that was initiated to resolve air-operated valve problems in the ESW system was a good initiative. Engineering response to industry Part 21 issues was good. (Section E2.1)

- The licensee completed thorough troubleshooting for the June 1999 Unit 1 HPCI system failure which had resulted in a white performance indicator. The root cause analysis was thorough and in-depth, and identified appropriate corrective actions to be taken to prevent recurrence. The corrective actions were completed in a timely manner. (Section E2.2)

- The engineering department's communication and interface with the maintenance and operations departments was good. Active discussions among engineering, maintenance, and operations were evident during the daily morning meeting and the daily leadership meetings. (Section E2.3)

- Engineering backlog was effectively managed, and showed a declining trend. Work prioritization was appropriately implemented through 'The Right List' program that focused on plant safety. (Section E2.4)

- The safety evaluation program procedures provided clear guidance for implementing the requirements of the 10 CFR 50.59 safety evaluation program. (Section E3.1)

- Implementation of the 50.59 safety evaluations was consistent with Limerick procedures and 10 CFR 50.59 requirements. The technical quality of the safety evaluations was good. The reviews by the PORC were thorough. (Section E3.2)

- Quality verification audits provided good insight into organizational performance. Strengths and weaknesses were identified and discussed. Deficiencies were placed into the corrective action program. (Section E7.1)

- Engineering self-assessments were of good quality. The findings and recommendations of these assessments and audits were tracked by the plant wide Plant Information Matrix. (Section E7.2)

- The audits performed by the independent safety engineering group were comprehensive, technically detailed, well-documented, and included appropriate recommendations. The group was staffed by engineers with extensive industry experience. (Section E7.3)

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Report Details

E1 Conduct of Engineering

E1.1 Plant Design Change Modification Reviews

a. Inspection Scope (37550)

The team reviewed nine permanent plant modifications installed during outage and non-outage periods to determine whether they were properly designed, implemented, and in compliance with regulatory requirements.

b. Observations and Findings

The modifications that were reviewed met NRC requirements and conformed to the licensee's administrative procedures. The modification packages were reviewed and approved by the appropriate review committees as required by the administrative procedures. Operation, maintenance, and surveillance procedures that were affected by the modifications were identified and updated. Controlled copies of as-built design documents, such as drawings and specifications, were either revised or marked up on an interim basis per administrative controls. The Updated Final Safety Analysis Report (UFSAR) sections that were affected by the changes were appropriately updated or marked up for revision. Where applicable, supporting calculations and design evaluations received the required technical and design verifications and independent reviews. Design information was correctly shared among the technical disciplines that were involved in the calculations. Design inputs from appropriate codes and standards and applicable design criteria were properly identified. Assumptions were technically sound and adequately documented, and acceptable methodologies were used. Post-modification tests, which confirmed the adequacy of the new designs, were appropriately implemented.

In-service Testing of Pressure Relief Valves

In April 1989, the licensee implemented modification 5010. The modification reclassified certain Unit 1 safety-related (ASME Code Class 2 and Class 3) pressure relief valves from active to passive to reduce the in-service test (IST) program requirements for this type of valve. While originally written for Unit 1, the modification subsequently was applied to Unit 2 also. Seventy-six relief valves in the emergency diesel generator cooling and starting air, control structure chilled water, residual heat removal, core spray, high pressure coolant injection and reactor core isolation cooling systems were removed from the IST program due to this change.

Technical Specification (TS) 4.0.5 requires in-service testing of ASME Code Class 1, 2, and 3 pumps and valves to be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code (The Code) as required by 10 CFR 50.55a. Modification 5010 was based on the 1986 Edition of the Code, which became part of Limerick Units 1 and 2 licensing basis by an NRC Safety Evaluation Report, dated March 5, 1991. The licensee's reclassification was based on its interpretation of Section XI, Articles IWV-1100 and IWA-9000; i.e., that relief valves were passive valves that were not required to change position to accomplish their safety-related functions during the course of shutting down the reactor to cold shutdown condition or mitigating the consequences of an accident.

The team determined that 52 of the relief valves that were removed from the IST program were based on a misinterpretation of Article IWP-1100. The article includes within Section XI scope "...certain Class 1, 2, and 3 valves which are required to perform a specific function in shutting down a reactor to the cold condition, in mitigating the consequences of an accident, or in providing overpressure protection" as defined in ANSI/ASME OM-1-1981. The scope statement in Section 1.1 of OM-1-1981 includes "...pressure relief devices in plant systems which are required to perform a specific function in shutting down a reactor or in mitigating the consequences of an accident." The inclusion of certain relief valves to the scope of IST programs was also discussed in Section 4.3.1 of NUREG 1482, "Guidelines for In-service Testing at Nuclear Power Plants," dated April 1995: "In Paragraph IWV-1100 of the 1986 edition of Section XI, the Code Committee increased the scope of the valves subject to IST to include those valves which protect certain Code class systems...."

During the first 10-year IST program interval (which ended on February 1, 2000, for Unit 1 and January 8, 2000, for Unit 2), 35 of the 52 valves either were replaced, refurbished, or tested in accordance with the licensee's preventive and corrective maintenance programs. However, the licensee stated that the activities probably did not conform strictly to the requirements of OM-1-1981 in all respects. No maintenance or testing was performed on 17 of the valves during the first 10-year interval. During this inspection, the licensee completed an acceptable operability determination for the affected systems and determined the systems to be operable. These systems included residual heat removal, high pressure coolant injection, core spray, and reactor core isolation cooling systems.

Failure to test certain ASME Code Class 2 and 3 relief valves in accordance with Section XI of the Code during the first 10-year IST program interval constituted an example of a violation of 10 CFR 50.55a(f), In-service Testing Requirements. The licensee issued PEP I0010799 to initiate corrective actions for this violation. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV) consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 05000352, 05000353/2000-001-01)**

Generic Replacement of Solenoid-Operated Valves

Design change ECR LG-99-00771 was issued in March 1999 to generically evaluate substituting certain ASCO series 206 and X206 solenoid valves with equivalent AVCO solenoid valves. In a comparison between the two types of valves, the licensee stated in Item K of the ECR that the valve coefficient (Cv) of the AVCO solenoids had a different value. The licensee determined at that time that response time was not critical for the equipment controlled by these valves and that the AVCO valves were acceptable. Subsequently, the scope of the design change was expanded to replace the ASCO solenoid valves of eight containment isolation valves in the drywell equipment drain sump system. The eight new valves had a 30 second maximum stroke time requirement to close per Technical Specification Table 3.6.3-1, Primary Containment

Isolation Valves. The licensee failed to perform an IST program review to evaluate the potential adverse effect on stroke time as a result of the design change. Solenoid valve SV-061-130, which is a sub-component of air-operated valve (AOV) assembly HV-61-130, was installed in Unit 1 on November 15, 1999. A review of the post-maintenance stroke test results indicated that the AOV closed between 9 and 10 seconds, which was within the allowed time limit. The licensee issued ECR 00-00216 to revise the original ECR to include an IST program review and a stop work order preventing further installation of AVCO solenoid valves in the drywell equipment drain system until the evaluation was completed. The licensee also issued PEP I0010787 on this issue. Failure to evaluate the effect of the solenoid valve replacement on AOV stroke time was a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

Plant modifications at Limerick were designed and implemented in compliance with the NRC regulations. An adequate system was in place to ensure that affected drawings, procedures, and design documents were updated to reflect the modifications. Calculations, analyses, and output documents used appropriate codes and regulatory requirements as design inputs. Assumptions were technically reasonable and were appropriately documented. Design information between technical disciplines was used correctly.

A 1989 modification incorrectly excluded a large number of ASME Code Class 2 and 3 relief valves from the IST program. This was a non-cited violation of 10 CFR 50.55a.

E1.2 Temporary Plant Modification Reviews

a. Inspection Scope (IP37550)

The team reviewed temporary plant modifications (TPM) to determine whether they were properly designed, implemented, and in compliance with regulatory requirements. The team reviewed the implementation procedures and guidance provided, the extent of engineering involvement in safety evaluations for the temporary modifications, and the timely removal of the TPMs. Records of post-installation testing and modification tagging requirements were also reviewed.

b. Observations and Findings

Procedure MOD-C-07, “Temporary Plant Alterations (TPAs),” Revision 4, dated January 26, 1998, provided clear guidance for installing and removing temporary modifications. The team reviewed six completed TPAs and found that they properly addressed the specific plant issues, and that the TPAs were implemented in accordance with Procedure MOD-C-07. In each TPA, the effect on plant safety, licensing requirements, and post-alteration testing were considered appropriately. For each TPA, engineering performed a 10 CFR 50.59 determination and reviewed the effect of the TPA on the UFSAR and Technical Specifications. There was documentation to indicate that the TPAs were correctly tagged on installation, and that the tags were removed on completion. Each of the six completed TPAs were removed in less than 12 months.

The status charts of nine presently open TPA's were scheduled for completion and removal within 12 months.

c. Conclusions

Temporary plant alterations (TPA) were properly designed and implemented. Engineering involvement in safety evaluation determinations was evident. Post-installation testing (where necessary) and modification tagging requirements were in accordance with the procedures. There were no long-standing TPAs. The licensee provided adequate controls for the installation and timely removal of TPAs.

E1.3 Design Bases and Configuration Controls

a. Inspection Scope (37550)

The team performed a limited design basis review of the emergency service water (ESW) and high pressure coolant injection (HPCI) systems to assess the configuration controls that were utilized by the licensee to maintain the plant design basis current. The review included the Updated Final Safety Analysis Report (UFSAR), design basis documents (DBDs), design calculations, system and component specifications, modifications and safety evaluations, drawings, and operating and surveillance procedures. The review of system surveillance activities focused on the licensee's in-service test (IST) program requirements.

b. Observations and Findings

Reviews of Emergency Service Water System

The ESW system was in an increased monitoring status in accordance with 10 CFR 50.65(a)(1) (maintenance rule) due to having exceeded the licensee's performance criteria of one maintenance preventable functional failure and 10 functional failures per 24 month period. The failures were attributed to the corrosion of gate valve internals, sticking of solenoid-operated pilot valves, and corrosion of certain small bore piping segments and unit cooler stub pieces. The licensee established appropriate monitoring goals, and was implementing appropriate corrective actions, including modifying valve internals, replacing solenoid-operated valves with valves of improved designs, replacing degraded piping, and developing new preventive maintenance tasks. The team verified that the UFSAR, system DBDs, design calculations, controlled drawings, and other design documents were updated to reflect system modifications. For example, the ESW system DBD, calculations, and applicable sections of the UFSAR were properly updated when minimum flow requirements and heat removal capabilities were changed by physical modifications or analyses. Safety evaluations that were performed in accordance with 10 CFR 50.59 adequately documented the bases for concluding that no unreviewed safety questions were created by the changes. Design documents were controlled, maintained current, and readily retrievable. Licensing commitments, such as generic letter responses, corrective actions documented in licensee event reports, and responses to NRC's Notices of Violation were met.

In-service testing of ASME Code Class 1, Class 2, and Class 3 components was performed in accordance with 10 CFR 50.55a and Section XI of the ASME Boiler and Pressure Vessel Code (the Code), 1986 Edition. Specification ML-008, “Pump and Valve In-service Testing (IST) Program First Ten Year Interval,” Revision 6, dated January 30, 1998, contained the administrative requirements, test schedules and requirements, relief requests, and deferred test justifications for the Limerick IST program. It also contained detailed component basis documents that provided information regarding the safety functions and IST requirements of the components included in the program. The team reviewed selected surveillance procedures against the specification and the Code. With some exceptions (discussed below), the licensee’s IST program for the ESW system met the Code requirements concerning scope, test frequency, and method. Relief requests for alternative test methods and impractical test requirements met the requirements of 10 CFR 50.55(a), and deferred tests were adequately justified.

For pump testing, Article IWP-3100 of the Code requires that the resistance of the system be varied until either measured differential pressure or flow rate equals the corresponding reference value. The test quantities in Table IWP-3100-1 then are evaluated against the acceptance criteria in Table IWP-3100-2 to verify that the pump is operating within the allowable range. In 1991, the licensee determined that because of system design, it was difficult to establish a fixed pump reference value during successive quarterly tests. The licensee developed pump reference curves from data taken during the special tests. The tests recorded differential pressure and flow rate data at eight or nine points over a range of approximately 3000 to 5200 gallons per minute (gpm). The range approximated pump conditions between shutoff head and twice the minimum flow rate required in the accident analyses. The test instruments met the Code accuracy requirement specified in Table IWP-4110-1 (± 2% of full scale). The curves were reproduced in the pump surveillance procedures with parallel curves representing the allowable ranges of Table IWP-3100-2. During the test, the operators measured flow rate, calculated total pump head from spray pond level and pump discharge pressure, and marked the results on the curves. The use of a pump curve rather than a fixed reference value to perform quarterly IST of the ESW pumps was an alternative to the requirements of Article IWP-3100 of the Code. Between August 1991 and December 1999, the licensee did not request or receive authorization from the NRC Director of Nuclear Reactor Regulation prior to implementing the alternative test method as required by 10 CFR 50.55a(a)(3). A relief request prepared for the second 10-year IST program interval was submitted to the NRC in December 1999 but had not been approved at the time of the inspection. This constituted a second example of a violation of 10 CFR 50.55a(f), which is being treated as an NCV consistent with Section VII.B.1.a of the NRC Enforcement Policy. The licensee issued PEP I0010798 to initiate corrective actions for this violation. **(NCV 05000352, 05000353/2000-001-01)**

The licensee did not invoke its administrative design control procedures in developing the pump reference curves from the 1991 pump tests. Thus, the method of constructing the curves, bases for rejecting certain of the test data, and performance of independent reviews were not documented. Despite the accuracy of the instruments that were used during the tests, the curves reproduced in the surveillance procedures lacked sufficient precision to satisfy the Code accuracy requirements. This is an example of a violation of 10 CFR 50, Appendix B, Criterion III, which requires measures to be established to ensure that applicable regulatory requirements are correctly translated into procedures, and to provide for verifying or checking the adequacy of design. This violation is in the licensee's corrective action program as documented in PEP I0010798. This Severity Level IV violation is being treated as an NCV consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 05000352, 05000353/2000-001-02)**

Review of High Pressure Coolant Injection System

The HPCI system design conformed to design basis and licensing requirements specified in the technical specifications and the UFSAR. The piping and instrumentation diagrams (P&ID) agreed with the UFSAR system description. No discrepancies between the as-built configuration and the P&IDs were identified during a system walkdown. During the walkdown, the team verified that two design modifications had been completed: (1) Modification P-00114 (Unit 1) and P-00227 (Unit 2) removed or abandoned equipment associated with the RHR steam condensing mode of operation, and (2) ECR LG99-00782 changed a Unit 2 HPCI turbine steam inlet steam trap. The modifications were appropriately reflected in the latest system P&ID revision.

The team identified problems with the IST of certain check valves associated with the HPCI system. Valves 56-1F057 and 56-1F048 were required to pass at least 50 gpm of ESW through the HPCI turbine lubricating oil cooler. Surveillance test procedure ST-6-055-230-1, "HPCI Pump, Valve and Flow Test," Revision 38, dated February 8, 2000, tested forward flow through valve 56-1F057 by verifying flow through a downstream vent valve. Forward flow through valve 56-1F048 was verified by checking that the HPCI vacuum tank high/low level annunciator was not alarming.

Article IWV-3522 of the Code requires a full stroke exercise of check valves every three months. Confirmation that the valve disk moves away from the seat shall be made by some positive means, such as by a position indicating device or appropriate pressure indications in the system. The NRC provided guidance for full stoke exercising of check valves in Position 1 of Generic Letter (GL) 89-04, "Guidance on Developing Acceptable In-service Testing Programs," and Appendix A of NUREG 1482, "Guidelines for In-service Testing at Nuclear Power Plants". Position 1 of the GL defines a full stroke exercise as the ability to pass the maximum required accident condition flow through the valve. A valid full stroke exercise by flow requires that the flow rate through the valve be known. NUREG-1482 states that some form of quantitative criteria should be established to demonstrate the required flow rate and to detect any degradation of the valve (Appendix A, Question Groups 1 and 7). The licensee's test method for the check valves was not sufficiently quantitative to demonstrate passage of the required 50 gpm flow rate, and thus qualified as only a partial flow exercise. This constituted a third example of a violation of 10 CFR 50.55a(f), which is being treated as an NCV consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PEP I0010867. **(NCV 05000352, 05000353/2000-001-01)**

Check valve 56-1F052 was within the ASME Class 2 portion of the HPCI barometric condenser discharge piping and functioned as a seismic class boundary valve. The valve was not included in the licensee's IST program as required by Article IWV-1100 of the Code or periodically exercised to the closed position in accordance with Article IWV-3522 of the Code. There was no analysis or evaluation of HPCI system qualification or performance to demonstrate that the check valve had no safety function to close following a seismic event. The team concluded that IST of the valve was required by the Code. This constituted a fourth example of a violation of 10 CFR 50.55a(f), which is being treated as an NCV consistent with Section VII.B.1A of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as documented in PEP I0010878. **(NCV 05000352, 05000353/2000-001-01)**

There were conflicting minimum flow requirements among various HPCI system documents. UFSAR Section 6.3.2.2.1 specified the minimum flow to be 500 gpm. The team reviewed Loop Uncertainty Calculation for Loop Number FT-055-2N051, dated February 23, 1998, which provided the set point basis of 500 gpm (set at 550 gpm with 50 gpm accounted for instrument uncertainty) for the minimum flow valve control. However, Section 3.2.8 of the HPCI DBD stated that the minimum flow was 560, and Section 3.2.8.5 stated that, "reducing the minimum flow below 560 gpm impacts the operation of the HPCI pump". The licensee issued ECR A1252928 on February 23, 2000, to resolve this conflict. The licensee also performed an operability determination which demonstrated that HPCI pump operation was not adversely affected by the lower minimum flow rate.

After this inspection was completed, the licensee provided a letter from General Electric (letter GE-OS-156, dated February 21, 1990) which states: "The 500 gpm (minimum) value on the [FSAR] process diagram was an absolute value; however, it is in error. This value should be 560 gpm (minimum) .... The basis for the 560 gpm value was a requirement for the minimum flow to be 10% of the design rated flow (5600 gpm) from the pump manufacturer". This constituted the second example of a violation of 10 CFR 50, Appendix B, Criterion III, Design Control, which requires that design control measures be established to assure that the design basis is correctly translated into specifications, drawings, and instructions. The violation is being treated as an NCV consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 05000352, 05000353/2000-001-02)**

c. Conclusions

The ESW and HPCI systems were capable of performing their design basis functions. The design bases and configurations of the ESW and HPCI systems were adequately controlled. However, several examples of noncompliance with 10 CFR 50.55a, pertaining to in-service testing of components in these systems, were identified. In addition, a violation involving two examples of inadequate design controls was also identified. These deficiencies were entered into the licensee's corrective action program and treated as non-cited violations.

E2 Engineering Support Facilities and Equipment

E2.1 Technical Issues Identification and Resolution

a. Inspection Scope (37550)

The team reviewed technical support to the operations and maintenance organizations to assess the quality of the licensee's program and procedures for identifying and resolving technical issues and emergent plant problems. During the inspection, the team also conducted interviews and held discussions with management and technical personnel in the licensee's engineering, maintenance, and operations departments.

The team reviewed: (1) approximately 50 Equipment Performance and Material Condition Reports (EPMCR); (2) six operability determinations performed for nonconformance reports (NCR); (3) two failure analysis reports; (4) four class 'A' root cause analyses; (5) five licensee event reports (LER) including analysis and resolution; and (6) two PEPs that dealt with the resolution of licensee identified plant problems.

b. Observations and Findings

The EPMCRs covered a wide range of evaluations, including operations concerns and maintenance rule a(1), yellow and red systems status. The evaluations were technically valid, and the reports clearly indicated the responsible personnel and the status of the item. The tracking of the report was done through the computerized Problem Management System (PMS).

The operability determinations and root cause analyses were technically thorough, and evaluations were well documented. Also, the failure analyses and LER evaluations were comprehensive and well documented.

The licensee had implemented a program called 'Engineering Response Team,' in which an engineering department manager/supervisor was designated on a weekly basis to be the focal point for arranging and managing the engineering effort for an emerging plant problem. The assigned person (Engineering Duty Manager (EDM)) was responsible for assembling a response team, scheduling work, and assuring timely resolution of the problem/concern. The engineering coordinator had the authority and flexibility to interface with other organizations, prioritize the emerging work, assign and direct engineering personnel, and schedule the work.

The licensee stated that they had initiated an air-operated valve (AOV) program to deal with the AOV problems they had identified (documented in PEP I000858) in the ESW system. Based on discussions with the licensee and a review of documentation, the team determined that the licensee was actively developing an AOV program that followed closely the recommendations of the Joint Owners Group AOV Program document. The design verification and testing aspects of this program satisfied the design-basis capability issues related to the ESW air-operated gate valves, which were classified as safety-related, high risk-significant, by the licensee. In addition, a method for providing consistent bench set and air regulator settings for AOVs was also included in this program. The team determined that the voluntary program implemented at Limerick was a positive step to address issues involving AOVs.

The team reviewed the licensee's responses to four 10 CFR 21 reports of defects or noncompliances that were issued by manufacturers in 1999. The reports involved defects in Woodward EGM controllers, ASCO series NH hydramotor actuators, C&D battery grids and plates, and ABB K-Line circuit breakers. The team found that engineering's evaluations of the 10 CFR 21 reports were technically sound and were performed in a timely manner (i.e., within 30 days of receipt).

The team reviewed an operability determination that was performed by licensee engineering when pinhole leaks were identified in the emergency service water (ESW) supply and return piping serving the 2B and 2D residual heat removal pump room unit coolers. The four pinhole leaks were identified by the licensee on January 6, 2000, and operations requested engineering support to evaluate the ESW system with the leaks. An initial determination of operability was made promptly based on visual examination of the leaks, coupled with the review of a more detailed evaluation that previously had been conducted for similar leaks at Unit 1. Non-destructive examination (NDE) of the leaks was required to confirm that the structural integrity of the pipe was not challenged, and that the previous evaluation bounded the current leaks. NDE personnel performed satisfactory confirmatory examinations of three of the four leak locations on January 10. However, due to mis-communication between engineering and work control, the fourth location was not examined until February 8, 2000. The examination confirmed that the pipe was structurally sound. Failure to perform a timely NDE of the fourth leak location constituted a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

The Engineering Response Team concept supported engineering's timely response to routine technical problems and emerging plant issues. Engineering support to maintenance in resolving maintenance problems and implementing the maintenance rule was satisfactory. The licensee usually conducted thorough investigations for the identified technical issues. The air-operated valve program that was initiated to resolve AOV problems in the ESW system was a good initiative. Engineering response to industry Part 21 issues was good.

E2.2 Corrective Actions In Response To Unit 1 HPCI System Failure

a. Inspection Scope (IP 95001)

On June 23, 1999, the Unit 1 HPCI system failed to start during a surveillance test using Procedure ST-6-055-230-1, " HPCI Pump, Valve and Flow Test". The licensee reported the event to the NRC on June 23, 1999 as an event or condition that alone could prevent fulfillment of a safety function. The licensee also issued licensee event report (LER) 1-99-08 on July 23, 1999, to report this event. The team reviewed actions taken in response to this event to determine whether the licensee had appropriately identified the root cause and whether effective corrective actions had been taken to prevent recurrence.

b. Observations and Findings

Unit 1 was at 100% power when the event occurred. The licensee's initial observation of this event indicated that HPCI turbine control valve FV-56-111 failed to open in response to the HPCI initiation signal. The licensee promptly initiated Action Request (AR) A1216585 to commence troubleshooting. The troubleshooting result (documented in PEP I0009965) indicated that the HPCI turbine governor electro-hydraulic regulator (EG-R), which controlled the turbine control valve position, was bound up. The binding prevented the EG-R internals from moving and thereby prevented the turbine control valve from opening.

The licensee replaced the defective EG-R on June 24, 1999, under Work Order C0189370. However, a technician reversed the leads when installing the new EG-R. During the post-maintenance slow start test, the HPCI pump tripped on over-speed. The installation deficiency was corrected and the system was retested successfully. On June 25, 1999, the licensee declared the HPCI system operable.

The licensee's laboratory test indicated that the EG-R binding was caused by rusting of the EG-R internals. The root cause analysis (documented in PEP I0009964) determined that the corrosion of the EG-R internals was caused by moisture intrusion that had occurred during the April 20, 1999 Unit 1 scram and HPCI initiation. During the event, the HPCI system ran for approximately 13.5 hours. During the extended run, the barometric condenser did not operate as designed and water backed up into the turbine and seeped out the turbine steam glands. The water then entered the oil system through the bearing cavities. This resulted in significant moisture intrusion into the HPCI lube oil system. Oil samples taken following this event indicated a moisture content of approximately 5.04%. Section 3.3.3.2 of the HPCI Design Baseline Document stated that the turbine lube oil moisture content should be less than 0.2%, and that if the moisture content was above 0.5%, action shall be taken to reduce water content. Subsequently, the licensee took immediate action (documented in AR12116806) to drain the used oil and to remove moisture from the lube oil system (using water absorbing filters). The licensee did not replace the EG-R at that time due to the incorrect assumption that all residual moisture had been removed from the oil system.

The licensee determined the primary cause of the barometric condenser failure to be set point drift (upward) of the lube oil cooler pressure control valve (PCV-056-1F035, a self-regulating valve). The downstream piping from this valve is connected to the HPCI vacuum tank condensate pump discharge. The higher back pressure reduced the pump's capacity causing condensate level to rise in the barometric condenser, backing up into the turbine glands. The licensee reset the PCV to the correct pressure setting. In July 1999, the licensee issued PEP I0009964 Evaluation 5 to monitor the set point drift condition of the PCV. During the October 10 and 11 surveillance test, the licensee found that the PCV was not controlling the pressure adequately, and the PCV was replaced in February 2000. The post-maintenance test demonstrated that the new valve maintained output pressure within the prescribed range (58 - 62 psig).

The team's review of the maintenance history of the PCV indicated the valve had been rebuilt three times due to set point drift problems from 1993 to 1998. The last time it was rebuilt was in May 1998 when the set point had drifted from 60 psig to 88 psig.

The licensee completed a failure analysis of the PCV and found (from the result of a Laboratory test) that corrosion of the valve internal sensing lines had degraded valve performance. The corrosion appeared to result from leakage through a cracked diaphragm. The analysis recommended replacing the susceptible soft parts of the PCV on a periodic basis to minimize the probability of this type of failure. Implementation of this recommendation was being evaluated by the licensee. The licensee stated that it would continue to monitor the set point of the new PCV.

The licensee also addressed, in PEP I0009964, the generic implications of this event, especially for the failure of the PCV, for the reactor core isolation cooling (RCIC) system, for Limerick Unit 2, and for the two units at Peach Bottom.

The team found that the root cause evaluation results and corrective actions were consistent with those reported in LER 99-08.

c. Conclusions

The licensee completed thorough troubleshooting for the June 1999 Unit 1 HPCI system failure, which had resulted in a white performance indicator. The root cause analysis was thorough and in-depth, and identified appropriate corrective actions to be taken to prevent recurrence. The corrective actions were completed in a timely manner.

E2.3 Engineering Interfaces With Other Departments

a. Inspection Scope (37550)

The team reviewed the engineering department's process and procedures related to communication, interface with other departments, management reporting, and documentation to assess the effectiveness of the licensee's site engineering organization in these areas. The team also attended regular interface meetings to observe the process and contents of the meeting, and conducted interviews with engineering, maintenance, and operations personnel.

The assessment of this area was performed in conjunction with the review of the area discussed in Section E2.1.

b. Observations and Findings

The licensee had implemented a work control process called 'The PECO Nuclear On-Line Work Management Process', which integrated the efforts of both work and support groups into a series of activities to support emerging plant issues and on-line maintenance during plant operation, and outage activities during refueling outages. The cornerstone of the process was the work process meetings: (1) daily morning meeting (6:30am) attended by representatives of site organizations to review the plant status, discuss new action report initiated since last meeting, and evaluate emergent, and investigative work for prioritization and scheduling; (2) daily plant status review meeting (3:00pm) attended by site organization personnel to review the daily work plan. The team observed that the discussions were frank, detailed, and emphasized operational safety and imperatives.

The team also observed that the system engineers closely interacted with the onsite design engineers in the areas of failure analyses and operability determinations.

In addition to the above, the engineering organization analyzed plant performance indicators and regularly reported the findings to senior management for inclusion in the senior management report.

c. Conclusions

The engineering department's communication and interface with maintenance and operations department was good. Active discussions among engineering, maintenance, and operations were evident during the daily morning meeting and the daily leadership meetings.

E2.4 Engineering Backlog and Prioritization

a. Inspection Scope (37550)

The team reviewed the licensee's work prioritization process for safety significant work activities and controls of engineering backlogs to assess performance in these areas.

b. Observation and Findings

The prioritization of engineering work load was a part of the plant wide work management process through a process called 'The Right List'. The Right List is intended to provide a means to highlight and establish priority for work activities in a given work week. It was a process that ensured that work was appropriately scoped and evaluated against the prioritization criteria. The work thus scoped and prioritized was included into the right list and focus was maintained to ensure implementation of the work.

The team reviewed the Right List prioritization criteria and determined that they appropriately emphasized corrective maintenance (CM) on systems identified as Maintenance Rule "a(1)" or operator work-around; and CM which improved system performance, operability, safety, and/or ALARA requirements. The review of the engineering work backlog indicated that the work had been effectively managed. The team noted a declining trend in the backlog of engineering work.

c. Conclusions

Engineering backlog was effectively managed, and showed a declining trend. Work prioritization was appropriately implemented through 'The Right List' program that focused on plant safety.

E3 Engineering Procedures and Documentation

E3.1 10 CFR 50.59 Program Implementation Procedures

a. Inspection Scope (IP 37001)

The team reviewed Limerick procedures and guidance provided for the implementation of the 10 CFR 50.59 safety evaluation program to determine their adequacy.

b. Observations and Findings

Procedure LR-C -13, “10 CFR 50.59 Reviews,” Revision 8, dated June 30, 1998, provided clear guidance in implementing the requirements of 10 CFR 50.59 safety evaluation program. Supplemental procedures, such as LR-CG-13, “Performing 10 CFR 50.59 Reviews,” Revision 3, LR-CG-13-3,“10 CFR 50.59 Screening,” Revision 5, and LR-CG-13-2, “Review Determination Checklist,” Revision 3, provided additional guidance for the screening and preparation of safety evaluations. The responsibilities and authorities to implement the screening and determination processes, safety evaluations, documentation, review, and approval were clearly defined in the these procedures. The plant operations review committee (PORC) provided reviews and approval of all safety evaluations. The results of the 10 CFR 50.59 evaluations were reported annually to the NRC.

c. Conclusions

The safety evaluation program procedures provided clear guidance for implementing the requirements of the 10 CFR 50.59 safety evaluation program. The plant operations review committee (PORC) reviewed and approved the safety evaluations. The results of 10 CFR 50.59 evaluations were reported annually to the NRC.

E3.2 10 CFR 50.59 Safety Evaluation Reviews

a. Inspection Scope (IP 37001)

The team reviewed selected engineering change request (ECR) documents, which covered a wide range of engineering disciplines, to determine whether the10 CFR 50.59 safety evaluation process was appropriately implemented. Selected safety evaluations were also examined, along with design changes that the licensee had implemented without formal safety evaluations. The team also attended three Plant Operations Review Committee (PORC) meetings to determine how safety evaluations were reviewed and accepted by the Committee.

b. Observations and Findings

The team reviewed the safety evaluation determinations of twelve ECRs and found nine ECRs requiring safety evaluations. These determinations proceeded in accordance with procedure LR-CG-13, Revision 8. The safety evaluations comprehensively addressed the safety issue questions directed by 10 CFR 50.59. The technical quality of the safety evaluations was good. In cases where a formal safety evaluation was not performed, the team found the licensee's determinations to be valid and consistent with administrative procedures. The team also confirmed that the affected sections of the updated final safety analysis report (UFSAR) were appropriately updated. In addition, the team also reviewed several changes in station procedures and found that these changes were also subject to safety evaluation determinations.

An important part of the Limerick 10 CFR 50.59 Program was the involvement of the PORC, which reviewed and approved each design change. The committee consisted of personnel of a wide diversity in plant operation functions. The team attended three PORC meetings in which the safety evaluations were reviewed in strict adherence to the rules of 10 CFR 50.59. The review and approvals by the PORC at these meetings were thorough, including a page by page review of the proposed safety evaluations. Any required changes to the safety evaluations were adequately discussed at the meeting. Some safety evaluations were rejected by the PORC and returned for revision.

c. Conclusions

Implementation of the 50.59 safety evaluations was consistent with Limerick procedures and 10 CFR 50.59 requirements. The technical quality of the safety evaluations was good. The reviews by the PORC were thorough.

E3.3 10 CFR 50.59 Safety Evaluations Program Training and Qualification

a. Inspection Scope (IP37001)

The team reviewed the licensee's 10 CFR 50.59 qualification training program to determine whether the safety evaluation preparers were adequately trained to perform their duties. The team also interviewed a training instructor and several engineers to assess their knowledge in this area.

b. Observations and Findings

The licensee had an acceptable training program for 10 CFR 50.59 safety evaluations. The training materials adequately covered the requirements and implementation of safety evaluation program. Interviews with a training instructor and several engineering personnel found them to be proficient in implementing the 10 CFR 50.59 safety evaluation program. In addition the quality of ten 10 CFR 50.59 safety evaluations reviewed by the team was determined to be good. Therefore, the team determined that the licensee had an acceptable training and qualification program for the 10 CFR 50.59 safety evaluation.

c. Conclusions

Engineers involved with design changes received proper training for implementing the 10 CFR 50.59 safety evaluation program. The training materials adequately covered the requirements and implementation of safety evaluation program. The instructor of the safety evaluation training was familiar with the program. Interviews with the engineers involved with safety evaluation preparation found them knowledgeable of the safety evaluation requirements.

E7 Quality Assurance in Engineering Activities

E7.1 Quality Assurance Audits of Engineering Activities

a. Inspection Scope (37550)

The team reviewed several audits conducted under the licensee's Quality Verification (QV) program. The review encompassed assessing the quality of the audits, verifying that deficient conditions identified during the audit were entered into the licensee's corrective action program, and verifying that corrective action was implemented.

b. Observations and Findings

The licensee's audit program was governed by a predefined schedule that outlined the areas that should be examined to ensure that technical specification (TS) audit requirements were satisfied. In keeping with standard industry practice, before an audit was conducted, the auditors met with the client organization to discuss the audit scope and objectives, and discuss any concerns that the target organization had regarding the audit. Similarly, when the audit was completed, the auditors discussed their findings with the target organization.

Deficiencies identified during audits were entered into the licensee's corrective action system, the Performance Enhancement Program (PEP). Periodically, the QV department reviewed the status of items that had been entered into the PEP and verified that corrective actions had been implemented.

QV audits were thorough and comprehensive, and provided good insight into organizational performance. Each audit discussed organizational strengths and weaknesses, and also reviewed the effectiveness of corrective actions that were taken to address deficiencies identified during previous audits of that functional area.

c. Conclusions

Quality Verification audits provided good insight into organizational performance. Strengths and weaknesses were identified and discussed. Deficiencies were placed into the corrective action program.

E7.2 Self-Assessments of Engineering Issues

a. Inspection Scope

The team reviewed five engineering self-assessment reports to assess the technical content and the quality of the assessment effort, results, follow up of the observations and findings, and the overall quality of the licencee's self-assessment program.

b. Observations and Findings

The licensee had implemented an extensive self-assessment program. This assessment program was mandated by Quality Assurance (QA) procedure NP-QA-1. The assessments had adequate description of scope and the areas covered, and observations and findings including strengths and weaknesses. The self-assessments of the Engineering Response Team, and of the Maintenance Rule areas were good. The external peer assessment/audit of the station thermal performance program was of high quality. The assessment identified many strengths in the area, and also identified several areas of improvement.

The team verified that the observations and findings of these assessments and audits were tracked by the plant-wide computer tracking system known as Plant Performance Matrix.

c. Conclusions

Engineering assessments were part of the overall Quality Assurance self-assessment program, and controlled by a QA procedure. The internal engineering self-assessments were supplemented by scheduled QA audits. The engineering self-assessments reviewed were of good quality. The findings and recommendations of these assessments and audits were tracked by the plant wide Plant Information Matrix.

E7.3 Independent Safety Engineering Group

a. Inspection Scope (IP 37550)

The team reviewed the activities of the Independent Safety Engineering Group (ISEG) to assess the quality of the group's support to plant operations and maintenance. The review included procedures and selected ISEG reports. The ISEG's audits could be either self initiated or requested by other departments.

b. Observation and Findings

The licensee's safety engineering group program was covered by procedure NQA-28. The purpose of the procedure was to provide an operational framework for an independent technical review program conducted by an 'Independent Safety Engineering Group'. The primary objective of the ISEG program was to assess and assure the overall quality of plant operations and to identify areas for improving plant nuclear safety. Program and process effectiveness was the primary evaluation criteria with emphasis placed on plant operations.

Additionally, PECO Nuclear Directive ND-QA-1 provided the frame work for relationship between ISEG and all PECO personnel during the conduct of ISEG activities in performing and reporting assessments, issuing recommendations, and response to ISEG recommendations.

The team noted that in the past twelve months, the ISEG had performed forty-one brief and ten detailed audits. Out of the 41 brief audits, twenty-nine were self-initiated, four prompted by Nuclear Review Board, and seven were requested by QA. In the area of detailed audits, six out of ten were self-initiated.

c. Conclusions

The ISEG audits were comprehensive, technically detailed, well documented, and included appropriate recommendations. The group was staffed by engineers with extensive industry experience.

E8 Miscellaneous Engineering Issues (IP 92903)

E8.1 (Closed) IFI 98-05-02: Seismic Response of Agastat Relays. The Agastat relays at Limerick were seismically qualified using qualification test report No. ES-2000, "Qualification Test Report on Agastat EGP, SML and ETR Control Relays," dated July 11, 1980. During the June 1998 inspection, over-aged Agastat relays were identified. The NRC raised a concern that, during a seismic event, contact chatter in a relay that was aged beyond its service life could initiate or prevent an action that would interfere with the normal shutdown of the plant.

During this inspection, the licensee stated that it had completed a review of a 1988 Southwest Research Institute (SWRI) test report No. 04-173001, and concluded that contact chattering (in de-energized state only) was not affected by relay aging. The licensee's review of the original qualification document by Bechtel Corporation, "Circuit Analysis to Evaluate Chattering of Agastat Type EGP, ETR, and E-7024 Relays" dated June 1984, indicated that the relay contact chattering issue had already been addressed. Any relay chattering with greater that 2 millisecond (ms) duration was assumed to be failed (for safety-related function) in accordance with IEEE Standard C37.98-1978, "Seismic Testing of Relays". Since the seismic testing results indicated that the normally closed contacts in the de-energized relays chattered with about 15 to 20 ms durations, these contacts were supposed to fail the safety-related functions during the seismic event. The Bechtel analysis covered safety-related relays, and evaluated the effects of normally closed contacts during a seismic event. The team reviewed a sample of eight relays and found the evaluation acceptable.

The team interviewed the Limerick engineers responsible for relay applications and found them familiar with the IEEE Standard requirements for relay chattering. There were also station procedures that controlled relay applications. Procedure NE-CG-935, "Control Relays Applications," Revision 0, dated June 15, 1995, Section 7.1.4.6, Vibration, addressed potential contact chattering problems during vibrations; Procedure NE-CG-911, Dynamic Qualification of Equipment Design Guide" Revision 2, dated March 5, 1999, Section 1-1, "Class I/Category I Electro-Mechanical Relay Type Devices," also addressed the potential adverse effect of relay chattering on safety-related applications.

The team determined that the licensee adequately addressed the relay chattering concern.

E8.2 (Closed) IFI 98-05-03: Agastat Relays in a harsh environment. During a June 1998 inspection, the NRC identified three discrepancies in Limerick's qualified life and thermal aging calculations for Agastat relays located in harsh environments: (1) the temperature rise of panel internals was not accounted for in relay qualified life calculations; (2) the temperature rise in panel internals was not accounted for in post-accident thermal aging calculations; and, (3) sufficient temperature margins were not evident for the qualified life and post-accident thermal aging calculations.

The team's review of the Limerick Agastat relay list indicated that there were about 70 Agastat EGP and ETR relays in the Limerick environmental qualification program. Most of these relays were subjected to radiation-harsh-only environment. Only four of these relays were required to function post-accident (up to 180 days, to operate cooling fan motors). To resolve the first discrepancy, the licensee installed temperature recorders inside the panel where the Agastat relays were mounted to obtain the internal temperatures for one year (to account for the seasonal temperature changes). These temperatures were used to determine the relays' qualified life using Calculation LE-0089, "Qualified Life and Post Loss of Coolant Accident (LOCA) Operability Evaluation of Agastat Relays," Revision 2, dated August 11, 1998. The licensee assumed 100% energization time for the normally-energized relays even though the maximum energized time was about 95%. The team determined that this approach was acceptable. To resolve the second and the third discrepancies, the licensee initially added a 15°F margin for the first 10 days following a loss of coolant accident (LOCA) to cover the temperature rise in the panels and instrument uncertainties. However, from day 10 to day 180, sufficient margin was not evident. In response to the team's questions, the licensee revised the post-LOCA thermal aging calculation by adding 8°F to the whole 180-day duration. The team determined that this was acceptable since the typical panel internal temperature rise was about 5°F. The revised calculation resulted in a qualified life reduction of 2.2 years for two relays in Room 200 and another two relays in Room 207. The revised calculation would not affect the safe-operation of the four relays, since the oldest relay was only 4 years old and has more than 3 more years qualified life left. The team also determined that the use of the Arrhenius Equation for the calculation was acceptable, as the relays had been type-tested (in oven) to 185°F for 941.7 hours in the energized condition.

V. Management Meetings

X1 Exit Meeting Summary

The team met with licensee personnel at the conclusion of the inspection on March 10, 2000, and summarized the scope of the inspection and the inspection results. The licensee did not dispute the inspection findings at the meetings.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Alderfer	Senior Manager, Plant Engineering
C. Anders	Director Engineering
T. Bell	Quality Assurance
S. Bobyock	System Manager, Emergency Core Cooling
S. Breeding	Manager, Balance of Plant
F. Cook	Senior Manager, Design Engineering
C. Cooney	Design Engineering
W. Coyle	Electrical Manager, Nuclear Engineering
M. Gallagher	Plant Manager
S. Gamble	Experience Assessment
K. Knaide	Design Change Manager
W Lewis	Electrical Design Manager
M. McGill	Design Eangineering
S. Minnick	Mechanical Design Manager
J. Suskil	Vice President
P. Tutton	Civil Design Engineer
A. Wasong	Training

NRC

P. Bonnet	Resident Inspector
A Burritt	Senior Resident Inspector
B. Holian	Deputy Director, DRS
W. Ruland	Chief, Electrical Branch, DRS

PROCEDURES USED

IP 37001: 10 CFR 50.59 Safety Evaluation Program

IP 37550: Engineering

IP 92903: Follow-up -Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

NCV 50-352,353/00-01-01 In-service Testing of pumps and Valves (four examples)

NCV 50-352,353/00-01-02 Design Controls for Developing ESW Pump IST Curves and for HPCI Minimum flow set point.

Closed

IFI 50-352,353/98-05-02 Seismic Response of Agastat Relays

IFI 50-352,353/98-05-03 Agastat Relays in a harsh environment

LIST OF ACRONYMS USED

ANSI	American National Standards Institute
AR	Action Report
ASME	American Society of Mechanical Engineer
CFR	Code of Federal Regulations
CM	Corrective Maintenance
CTE	Change, Test, or Experiment
ECR	Engineering Change Request
EDM	Engineering Duty Manager
EG-R	Electro-Hydraulic Regulator
EPMCR	Equipment Performance and Material Condition Report
ESW	Emergency Service Water
F	Fahrenheit
GE	General Electric
GL	Generic Letter
IEEE	Institute of Electrical and Electronics Engineers
IFI	Inspection Follow-up Item
ISEG	Independent Safety Engineering Group
IST	In-service Test
LCR	Lock Rotor Current
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MCCB	Molded Case Circuit Breaker
MOV	Motor-Operated Valve
NCR	Nonconformance Report
NCV	Non-Cited Violation
NDE	Non-destructive Examination
NRC	Nuclear Regulatory Commission
P&ID	Piping and Instrument Diagram
PCV	Pressure Control Valve
PEP	Performance Enhancement Program
PMS	Problem Management System
PORC	Plant Operations Review Committee
PSA	Plant Safety Analysis
psig	Pounds
QA	Quality Assurance
QV	Quality Verification
RCIC	Reactor Core Isolation Cooling
TPA	Temporary Plant Alteration
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report