U.S. NUCLEAR REGULATORY COMMISSION
REGION I

DOCKET/REPORT NO. 50-293/95-22

LICENSEE: Boston Edison Company (BECo)

FACILITY: Pilgrim Nuclear Power Station (PNPS)

DATES: October 23 - November 3, 1995

INSPECTOR: Antone C. Cerne, Reactor Engineer

for [signature] 12/1/95
Antone C. Cerne, Reactor Engineer
Civil, Mechanical and Materials
Engineering Branch
Division of Reactor Safety
Date

APPROVED BY: [signature] for MCM 12/1/95
Michael C. Modes, Chief
Civil, Mechanical, and Materials
Engineering Branch
Division of Reactor Safety
Date

AREAS INSPECTED: This inspection involved a review of selected plant modifications, to include design changes and field revision notices and an assessment of the licensee's resolution of vendor problems. An issue involving the design control of increasing ultimate heat sink temperatures and the resultant engineering impact upon the heat removal model calculations and affected salt service water and reactor building closed cooling water systems was examined in detail. The inspector also evaluated management oversight activities affecting the Nuclear Engineering Services Group, to include a group reorganization, several engineering initiatives and betterment plans, and the conduct of system audits by the Quality Assurance Department, which provide an independent measure of the plant's configuration controls and effectiveness of the implementation of plant design changes. An exit meeting was conducted with senior licensee management personnel at the conclusion of this inspection.

REPORT DETAILS FOR ENGINEERING INSPECTION, NO. 50-293/95-22

1.0 PLANT MODIFICATIONS

The inspector reviewed the BECo plant design change (PDC) log for 1994-1995, selecting four PDCs for further engineering review and followup. The following PDCs and associated field revision notices (FRNs) were examined for specification of the appropriate technical standards and acceptance criteria, discussion of relevant testing requirements, and documentation of a supportable safety evaluation and an independent design verification record:

- PDC 94-06 Reactor Core Isolation Cooling (RCIC) System High Steam Line Flow Isolation Setpoint Change

- PDC 94-17 Underground Diesel Fuel Tanks Oil Spill Monitoring

- PDC 95-02 Replacement of the Emergency Diesel Generator Standby FRNs 60 & 61 Fuel Oil Booster Pump

- PDC 95-07 Residual Heat Removal/Fuel Pool Cooling Intertie Isolation

The inspector verified that the above PDCs had been subject to the requisite controls of the Nuclear Organization Procedure (NOP83E1) governing modifications to Pilgrim Nuclear Power Station (PNPS). The inspector also reviewed the Updated FSAR, affected system descriptions, and referenced PNPS procedures to confirm a consistent application of the plant design basis in the design change process, as well as the implementation of the required procedural revisions. Where appropriate, commitments documented in licensee event reports (LERs) and in response to NRC inspection report open items were also checked to ensure compatibility with the PDC provisions.

Overall, the inspector determined that the design change criteria were properly handled and that the engineering inputs were correctly processed. The Operations Review Committee (ORC) provided the required oversight of both the completed PDC packages and the resulting operational procedure changes. Where system testing was necessary to demonstrate functionality of completed modification activities, the inspector verified that such testing had been conducted or was scheduled and that "overlap" testing criteria, where appropriate, had been properly specified. The safety evaluations and supporting design documents clearly established that unreviewed safety questions were not relevant to the proposed design changes with one exception, as discussed in the following paragraph.

In following up PDC 95-07, the inspector learned that the design change (i.e., installation of an isolation valve) had been cancelled because an ASME Boiler & Pressure Vessel Code (Section XI) revision had obviated the need for the modification. In this case, the licensee had submitted to the NRC a request for relief from the inservice inspection (ISI) requirements of certain welds during the last refueling outage (RFO 10) based upon a commitment to implement the design change during the next RFO. With the adoption of the 1989 version of ASME Section XI after RFO 10, the licensee determined that ISI of the welds in question was no longer a code requirement; thus, rendering the valve installation unnecessary. The inspector reviewed the BECo relief request, the

NRC response, and the pertinent code changes and determined that the licensee's cancellation of PDC 95-07 was technically valid. However, the inspector found that some of the "quality and safety considerations" documented in the relief request (BECo Ltr. 95-015) dated February 9, 1995 were not soundly based. Specifically, the failure analysis did not appear to properly account for augmented fuel pool cooling (AFPC) Mode 2 operation (reference: PNPS procedure 2.2.85.2), which used the subject intertie line during RFO 10.

The inspector noted that the BECo "Long Term Program: Semi-Annual Report" to the NRC, dated August 31, 1995, included a commitment to submit a revised relief request based upon the code revision and subsequent cancellation of PDC 95-07. During this inspection, the licensee indicated that this revised submittal would also provide a more sound technical basis for waiver of the ISI of the intertie pipe welds during RFO 10 when AFPC mode 2 was in operation. Since current committed code requirements have been met and the licensee has agreed to update the docketed record on this matter, the inspector had no further questions regarding the status of PDC 95-07.

The inspector also raised some questions regarding FRNs 95-02-60 and 61, specifying the replacement of the standby fuel oil pump on the "A" emergency diesel generator (EDG). The design change involved an electrically equivalent modification to an EDG component function that is not considered safety-related. Through a review of the PNPS procedures, FSAR, and vendor (ALCO) manuals, the inspector verified that the licensee's engineering approach to this issue was technically sound. From an operations standpoint, the licensee had adopted the proper perspective regarding the relationship of the main gear-driven and standby fuel oil pumps to the operability of the EDGs (reference: inspection reports 50-293/92-81, 93-19, & 95-09). However, the inspector noted that the affected EDG alarm response procedures (ARPs) C103B & C104B - C5 did not clearly specify the correlation between subcomponent status and EDG operability, like the other ARPs for other safety components. The inspector discussed this observation with the Operations Department Manager, who indicated that a review of the subject ARPs would be conducted to ensure consistency with other alarm response guidance where the plant Technical Specifications and component operability are involved. This appeared to be an isolated inconsistency; the design change was appropriately controlled.

2.0 VENDOR ISSUE RESOLUTION

The inspector reviewed the following licensee problem reports (PRs), all of which relate to vendor engineering concerns for equipment and services provided by separate divisions within the General Electric (GE) Company:

- PR 95.0284 Ring-O Valve Bushing Material not suitable for the PNPS Temperature Service Conditions
- PR 95.9270 Inadequate Shutdown Margin (SDM) demonstrated by PNPS Procedure 9.16
- PR 95.9533 SBM Switch Cam Follower Rivet Defects

In accordance with the BECo NOP92A1 governing the Problem Report Program, the first two PRs above were categorized as Significance Level I ("significant"), while the latter was classified as Level II ("important"). Level I PRs require a formal root cause analysis (RCA) in accordance with PNPS Procedure 1.3.102 and also require actions to prevent recurrence. While the licensee received notice of the SBM switch rivet problem from a GE service letter, the other two problems were first discovered by the licensee on site.

With regard to PR 95.0284, BECo efforts to procure spare parts for four gate valves supplied by GE disclosed the fact that the installed bushings were made of a material that was rated below the normal operating temperature of the systems in which the valves were installed. The incorrect bushing material was replaced prior to plant restart from RFO 10, as documented in inspection report 50-293/95-13. During this inspection, the inspector reviewed the GE Nuclear Energy (GENE) nonconformance report (NCR IEBHJ-95-01), the BECo Supplier Finding Report (SFR 95-11), and a BECo Audit Report (95-10) of GENE, all addressing different aspects of the valve project and the inadequate valve bushing material. The inspector also reviewed the licensee's Quality Assurance Department procedure 16.10 for "Supplier Finding Reporting." In accordance with this procedure, the licensee has aggressively pursued with GENE the potential reportability of this problem under 10 CFR 21. Although corrective actions were adequate, the inspector determined that neither the vendor's NCR, nor the BECo SFR documented an RCA of a comprehensive nature that would be expected to reveal and address adequate "preventive" measures.

Similarly for PR 95.9270, which documents the termination of a local SDM test and is further discussed in inspection report 50-293/95-09, the inspector's review of the GE RCA for this problem revealed analyses that appeared more to justify the calculational deviations, than to provide the bases for effective preventive measures in the future. The revelation that the uncertainties associated with the local SDM test are great and that there are inherent limitations in the GE modeling methodology may provide insight into why the subject test did not reflect an inadequate SDM. However, given the purpose of PNPS procedure 9.16 and its relation to Technical Specification requirements, the inspector found sparse discussion of the design differences (e.g., the cold target eigenvalue calculations) and the actions to be taken in the future to preclude problem recurrence ("preventive" measure).

Based upon the review of the above two problem reports, the inspector indicated to the licensee that the rigor with which root cause analysis and corrective/preventive measures are pursued in accordance with PNPS procedure 1.3.102 for vendor-related PRs appears to depend upon the quality of the vendor RCA and of the vendor actions deemed sufficient to prevent problem recurrence.

Further evidence of this was provided in the followup of PR 95.9533, which documents a new problem with the manufacture of replacement SBM switches. As is documented in inspection report 50-293/95-14, several original SBM switches were found to require replacement as a result of the identification of cracked or potentially defective Lexan cam followers. The licensee appeared to have implemented a deliberate and carefully planned SBM switch replacement schedule when, in October 1995, it learned of a potential problem with the riveting operation on the cam followers for a certain population of replacement SBM switches.

Once the problem was identified, the licensee conducted an Engineering Evaluation, which placed all suspect switches in a QC Hold status, but determined that the switches replaced to date were operable until RFO 11, at which time the ones with the suspect rivets would be again replaced. The inspector assessed the bases for this engineering evaluation and found an acceptable justification for the recommended course of action. The review of additional documentation on this issue revealed a significant amount of licensee oversight of the vendor activities to address this problem. The adequacy of GE corrective actions to fix the questioned manufacturing process, establish proper inspection controls, provide effective QA overview, and address 10 CFR 21 concerns were all questioned by the licensee. While the licensee deserves credit for the aggressive pursuit of this vendor problem area, the comprehensive nature of the BECo involvement in this issue appears to be more driven by individual initiatives, rather than by programmatic controls. As a Level II PR, formal RCA of this vendor process problem was not formally required.

The inspector reviewed the BECo Quality Assurance Manual (BEQAM) section on "Design Control" and the Nuclear Engineering Services procedures on the "Review, Evaluation, and Acceptance of Supplier Design Documents" and the "Evaluation of Defects and Noncompliance." References to the recommendations of ANSI N45.2.11-1974 and N45.2.13-1976 were noted. In accordance with these quality standards, the licensee's problem report program is intended to deal generically with all significant conditions adverse to quality. In the cases of the above problem reports, where the issues relate to the adequacy of vendor controls, the ownership of corrective action items, particularly with regard to the measures taken to preclude problem recurrence, is less clear. While no areas of technical concern or unresolved safety issues were identified by the inspector during this PR review, the inspector considered the area of root cause analysis of vendor-related PRs to be a potential program weakness (293/95-22-02).

3.0 ELEVATED ULTIMATE HEAT SINK TEMPERATURES - DESIGN IMPACT

As documented in inspection report 50-293/94-14, the resident inspectors questioned the impact of elevated sea water injection temperatures upon the heat removal capability, and thus the operability, of the reactor building closed cooling water (RBCCW) system. During July 1994 and at earlier times, the sea water injection temperature to the RBCCW heat exchangers was found to have exceeded the 65 degree Fahrenheit (F) limit discussed in the station FSAR. The licensee issued PR 94.9297 to further evaluate this concern. Based upon existing engineering calculations and further reviews of the heat removal system capability, a licensee evaluation determined that the RBCCW system remained operable while the nonconforming condition of salt service water (SSW) temperatures in excess of the FSAR specifications continued to be assessed from engineering and corrective action perspectives.

From a design standpoint, the RBCCW system provides cooling for safety loads during worst case accident conditions based upon the capability to transfer 65 million BTU/hr to the SSW system. Of this heat transfer rate, 64 million BTU/hr represents the containment cooling load, as is currently specified in the plant Technical Specification (TS) Bases, 3.5.B. The core and containment cooling TS (4.5.B.1.a) requires each SSW pump to deliver 2700 gpm flow at a 55' total dynamic head (TDH) with 2500 gpm per pump being delivered to the RBCCW heat exchanger in each train. Two operable SSW pumps are required in each train; thus matching an assumed SSW flow rate of 5000 gpm through each RBCCW heat exchanger. Therefore, the design basis of each RBCCW heat exchanger appears to be the removal of 65 million BTU/hr during accident conditions assuming a SSW flow rate of 5000 gpm and a SSW inlet temperature of 65 degrees F.

Later in 1994 another problem report (PR 94.9385) was issued to address an identified mismatch between the calculations for the head gain across each SSW pump versus the TS surveillance requirement of 2700 gpm at 55' TDH. The TS pump performance criteria were determined to represent a head gain across the pump's discharge, which is approximately 40' above the impeller where the calculations assumed the head gain should be considered. Taking this alone into account raised each SSW pump's performance criterion from a 55' TDH to a 87.5' TDH at the impeller assuming the same 2700 gpm TS flow value. Additionally, assuming some factor of RBCCW heat exchanger plugging at the same SSW flow rate, further raises the required SSW pump TDH criterion.

The licensee conducted a safety evaluation (SE 2892) in November, 1994 to assess the impact of changing the SSW pump flow and TDH criteria upon the SSW and RBCCW safety system functions. Supported by existing (M183) and new (M630) BECo calculations, the licensee was able to demonstrate that reducing the minimum SSW flow rate to 4500 gpm had no adverse impact upon the design bases of the safety systems involved in the heat removal functions. In effect, with the safety functions verified, the reduction in the required SSW flow to 4500 gpm allows for an assumed RBCCW heat exchanger flow blockage (approximately 10%) and reduced SSW pump performance criteria (76.5 TDH at the impeller) to still remove the required 65 million BTU/hr heat load during accident conditions. It was noted, however, that these calculations continued to use a 65 degree F maximum SSW inlet temperature for assessment purposes.

With the recognition of the conflict between the TS criteria for the SSW pumps and the assumed calculational inputs for pump TDH and flow, as characterized in PR 94.9385, the licensee conducted full flow pump tests in 1994, demonstrating operability. The licensee also reviewed historical data to determine if the SSW pumps had evidenced test performance results that did not meet the current criteria (i.e., 2700 gpm at 87.5' TDH at the pump impeller). Even though some of this historical data indicated certain SSW pump performance characteristics below the required full flow TDH criterion, a licensee 10 CFR 50.73 evaluation in December, 1994 determined that this was not a reportable event. The licensee decision was based upon the inservice testing (IST) results, demonstrating acceptable pump shutoff head results, and engineering judgement that the pumps had not degraded (i.e., ASME Section XI considerations) below acceptable performance levels.

In January 1995, BECo - with contractor support - commenced a self-assessment activity involving a Service Water System Operational Performance Inspection (SWSOPI) of the SSW and RBCCW systems at PNPS. The SWSOPI Final Report was published on April 25, 1995, and documented findings related to the SSW flow, temperature, and system testing discrepancies discussed above. The SWSOPI also evaluated several other safety criteria (e.g., core standby cooling system pump NPSH and strainer clogging; bulk suppression pool temperature heatup) with impact upon an overall maximum acceptable heat removal capability during plant accident conditions. The SWSOPI team determined that the SSW and RBCCW systems were capable of performing their safety functions upon demand. The SWSOPI conclusions were in part based upon updated GE analysis of the impact of increased SSW temperatures upon the PNPS safety system heat removal capability (reference: GENE Ltr.G-HK-4-60, dated July 29, 1994), but also upon continuing BECo engineering efforts to address all the pertinent variables and revise the FSAR-documented, maximum SSW temperature of 65 degrees F to a 75 degree F value.

During this current inspection, the inspector reviewed the subject PRs 94.9297 and 94.9385 with its associated SE 2892; evaluated the applicability of existing GE decay heat removal calculations (NEDC-30915) and BECo calculations (M-186) to verify the heat transfer model and results (Calculation No. 183); and assessed a more recent GE analysis (G-HK-4-60) and the BECo Summary Report (dated October 20, 1995) providing the current status of the SSW temperature and pump performance issues related to the safety function of the RBCCW system to transfer 65 million BTU/hr to the SSW system. The inspector noted that inspection report 50-293/95-21 documents an unresolved item on the issue of the SSW temperature. An overall licensing question arose on whether individual FSAR assumed design values (e.g., a SSW flow rate of 5000 gpm, a SSW inlet temperature of 65 degrees F) represent part of the actual plant design basis or are basically design inputs into the heat transfer model, which establishes the removal of 65 million BTU/hr of heat as the incontrovertible design basis. The inspector did not fully explore this licensing question; instead reviewing the engineering record to evaluate current licensee efforts in this area and to determine if the licensee's engineering judgements and conclusions to date are supportable by valid calculations and other design documents. As a result of this review, the inspector identified the following issues:

- GE analyses (NEDC-30915) done in 1985 were found to include calculations involving a SSW temperature increase to 70 degrees F. However, additional sensitivity studies by GE, which investigated the SSW temperature range up to 75 degrees F, were only accomplished for the stuck-open relief valve event, not the more limiting design basis accident (DBA).

- The PNPS TS Bases (3.5.B) describe a somewhat misleading functional capability for the containment cooling system (i.e., removing 64 million BTU/hr). While this may address the maximum "containment" heat load, the additional safety-related heat loads establish the maximum system capacity requirements of 65 million BTU/hr as the design basis.

- A 1982 LER (82-026) identified a problem with the TS criteria for adequate surveillance testing of the SSW pumps. Proposed TS revisions that would have addressed the SSW pump flow and RBCCW heat exchanger blockage concerns were never effected. A problem report action item (PR 94.9297.02) attempts to evaluate why certain associated FSAR changes were not properly processed. However, a BECo assessment was not completed on the overall program that not only processes licensing changes, but also ensures consistency with design basis data.

- A clearer integration of the diverse aspects of this overall SSW problem needs to be documented. For example, PR 94.9385 is addressed with a safety evaluation (SE 2892) that reduces the allowable minimum SSW flow rate to 4500 gpm while maintaining the SSW temperature of 65 degrees F as an assumed calculational criterion. Conversely, the impact of a reduced SSW flow rate to the RBCCW system appears to affect some of the criteria used by GE (G-HK-4-60) in assessing the PR 94.9297 issue involving an allowed rise in the SSW inlet temperature from 65 to 75 degrees F. While this appears to be a multi-changed variable problem that may be solved with an allowable rise in suppression pool temperatures, no single document appears to comprehensively address all the changed parameters and their overall impact.

- The licensee 10 CFR 50.73 evaluation of the historical SSW pump performance data that did not meet the required 87.5' TDH at the pump impeller used engineering judgement of IST results to rationalize a potential violation (albeit in the past) of the plant TS. When the inspector apprised the licensee of this concern, a new problem report (PR 95.9572) was issued to address the further evaluation of the reportability of the identified deviant conditions.

In summary, the licensee engineering staff is currently working toward documenting in event analysis and equipment performance calculations the basis for PNPS operation with an inlet SSW temperature of 75 degrees F. BECo requires the support of GE for some reanalysis, particularly for environmental qualification considerations, and plans to complete all engineering evaluations and summary analysis, and provide a design report by March 1996. The inspector, in reviewing the existing calculations and engineering evaluations, identified no technical concerns that would question the methodology for the analysis accomplished to date or the bounds of the additional work. The inspector discussed with licensee management the efficacy of handling such a multifaceted problem under the direction of an engineering "project manager" to avoid the appearance of fragmentation in the oversight and integration of the different aspects this complex issue. With respect to the above inspector observations, pending the resolution of PR 95.9572 and further discussion regarding the TS and licensing basis concerns, these issues remain open as an update to Unresolved Item 50-293/95-21-01.

4.0 MANAGEMENT OVERSIGHT

Engineering Reorganization

The inspector interviewed the new manager of the Nuclear Engineering Services Group (NSEG) regarding the recent reorganization of the BECo nuclear business unit. The role of the corporate engineering services group in planning capital projects and providing engineering support to PNPS was addressed, as were the attendant programmatic controls and QA oversight functions for such services. The current NSEG organization chart was reviewed and personnel changes and functional moves (e.g., modifications management, drafting services) were discussed. The NSEG manager also detailed for the inspector the concept of how the "safety monitor program " (under development, as discussed below) would be coordinated with the current plant twelve-week rolling maintenance schedule to provide an enhanced view of overall plant safety from an equipment availability standpoint. The inspector indicated that such initiatives appeared beneficial to the station's future planning controls.

Engineering Initiatives

The inspector witnessed a demonstration of the PNPS Safety Monitor (SM) Program being developed as a tool for future plant configuration management and on-line risk monitoring. The SM uses an Individual Plant Examination (IPE) model in a PC Windows accessible environment to identify operable equipment and systems, display a measure of station risk in the identified plant configuration, prioritize component restoration, perform hypothetical risk assessments, and provide other risk profiles and related tasks. Discussion with one of the lead IPE engineers and review of the program description revealed that the SM Program is being coordinated with the plant operations department and with the station maintenance rule project team, as well as with EPRI's Risk and Reliability Work Station Project. Although this program is still in an inceptive phase, the goal of the SM to support work planning and on-line decision making is recognized as one that can enhance future system line-ups, configuration controls, and overall plant safety.

The inspector also observed use of the NSEG's 3-dimensional model, utilizing a computer aided design (CAD) system to assist various work groups by providing a 3D view of various areas in the plant. This project has been divided into three phases with the first phase, consisting of real-scale dimensioning of the station structures, RPV, main steam and feedwater piping, turbine generator, condenser, and feedwater heaters, already completed. With the CAD system, various areas of the plant can be viewed from different directions and rotated in space to accommodate design engineering and training needs. The inspector discussed the 3D Model applications with the responsible engineers and was apprised of the expected training benefits for maintenance and radiological protection personnel from the perspective of both efficient planning and meeting ALARA goals. The current schedule for this initiative projects additional phases of work to progress through 1996.

Priorities and Betterment

The inspector reviewed the Plant Manger's Top-10 Items Report, listing those issues deemed to have a significant impact upon plant performance. As controlled by PNPS procedure 1.3.110, this process prioritizes the action plan development and work implementation for a select number of projects. For example, the SSW design, temperature and flow issues discussed in section 3.0 of this report are included as an item in the Top-10 List. The inspector noted that most of the items on the list involve varying degrees of engineering involvement and project management control. The inspector reviewed some of the Summary Reports, which document the individual problems and planned corrective actions and noted appropriate engineering analyses where relevant to the issue development and recommended courses of action.

The inspector also reviewed an NSEG document detailing engineering challenges and betterment activities. The inspector noted among the assigned challenges were tasks involving the maintenance of up-to-date and accessible plant design information, the conduct of engineering self-assessment activities, and the implementation of an improved Plant Design Change Process. Several betterment initiatives, like the station switchyard improvements and the SWSOPI conduct (see section 3.0), have already been completed and were reviewed during past NRC inspections. Other betterment activities (e.g., system walkdowns, work control) are ongoing, providing opportunities for further plant improvements and process enhancements. The inspector determined that the goal orientation and planning vision provided by this NSEG document, as well as the Plant Manager's Top-10 List, were valuable initiatives demonstrating positive management oversight of the station.

System QA Audits

The inspector reviewed the Quality Assurance Department's Audit Report 94-07 for the reactor core isolation cooling (RCIC) system. The QA Department schedules one system audit each year with the inspector noting that the 1995 QA audit of the core spray system had been the subject of previous NRC inspection activities. The 94-07 Audit Report included a comprehensive review of RCIC design/configuration control activities and involved field verification of plant design changes (PDCs) and assessment of the adequacy of the post-modification testing for several system PDCs. FSAR and TS criteria were examined by the auditors for consistency with and incorporation into the applicable RCIC procedures and drawings. The inspector also noted the use of performance-based audit activities and concluded that such QA system audits exemplify a worthwhile independent assessment of a system's fidelity to its design and engineering status. Such audits are also a valuable management tool to gauge the effectiveness of existing plant configuration controls.

5.0 MANAGEMENT MEETING

The inspector discussed the issues and items under review with engineering, technical support, and licensing personnel throughout the conduct of this inspection. An exit meeting was held on November 3, 1995, during which the preliminary findings were presented to the licensee. The licensee acknowledged these findings and the inspector's conclusionary remarks. No proprietary information that was reviewed during the inspection is intended to be documented in this inspection report. The following personnel were in attendance at the exit meeting:

J. Alexander, Nuclear Training & Management Services Group Manager
N. Desmond, Regulatory Relations Group Manager
F. Famulari, Quality Assurance Department Manager
J. Gerety, Nuclear Engineering Services Group Deputy Manager
C. Goddard, Nuclear Services Group Manager
J. Keene, Regulatory Affairs Manager
W. Kline, Nuclear Engineering Services Group Manager
M. Lenhart, Senior Regulatory Engineer
F. Mogolesko, Project Manager
H. Oheim, Technical Section General Manager
L. Olivier, Vice President - Nuclear Operations
T. Sullivan, Plant Manager
T. Trepanier, Operations Department Manager

B. Korona, NRC Resident Inspector
R. Laura, NRC Senior Resident Inspector