U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 50-293/90-25

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: November 27 - December 31, 1990

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Approved by: John Rogge 1/8/91
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Inspection Summary:

Areas Inspected: Routine safety inspection of plant operations, radiological controls, maintenance and surveillance, emergency preparedness, security, safety assessment and quality verification, and engineering and technical support.

Results: Inspection results are summarized in the attached Executive Summary. One violation with three examples was identified in the area of radiological controls for the failure of onsite personnel to adhere to properly established radiological practices as required by station procedures and Technical Specifications (50-293/90-25-01, Section 3.0). One Unresolved Item was identified in the area of maintenance to assess the effectiveness of licensee corrective actions relative to the "B" emergency diesel generator voltage regulator oscillations (50-293/90-25-02, Section 4.2).

EXECUTIVE SUMMARY

Pilgrim Inspection Report 50-293/90-25
November 27 - December 31, 1990

Plant Operations: Off normal temporary system configurations continue to be well controlled. Operators took appropriate actions to ensure that Technical Specification thermal limit requirements were maintained during the December 8 rod pattern exchange. Plant staff response to the increased "B" recirculation pump seal leakage demonstrated effective interdepartmental coordination and communication.

Radiological Controls: The station continues to experience periodic unrelated instances in which properly established and posted radiological controls are violated due to inattention to individual radiological protection responsibilities.

Maintenance and Surveillance: The maintenance team inspection observation of the screenhouse fire protection system material condition indicates that increased attention to this area is warranted. The inspector expressed concern regarding the licensee response to the "B" emergency diesel generator KVAR oscillations during surveillance testing. The condition was not annotated on the surveillance procedure. A formalized analysis of the operational effect of the condition was initiated after inspector questioning. Utilization of a recirculation pump seal cartridge mockup to validate the seal replacement procedure and provide hands on training was a positive initiative.

Emergency Preparedness: The fourth quarter combined functional drill effectively demonstrated the readiness of the impacted portions of the emergency plan.

Security: The facility security program continued to be effectively implemented. The annual QA audit of the security program was comprehensive and performance based. Field assessment resulted in the enhancement of the intrusion detection system.

Safety Assessment and Quality Verification: The licensee event reports (LERs) continue to be of excellent quality. Licensee activity to support closure of previous NRC inspection issues is noteworthy.

Engineering and Technical Support: The licensee provided a prompt and technically well developed response to NRC questions regarding engineering analysis for hydrodynamic transients on the RHR head spray line and for masonry block wall anchor sleeves.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

At the start of the report period Pilgrim Nuclear Power Station was operating at approximately 100% of rated power. On December 8 power was reduced to approximately 50% to backwash the main condenser and to perform a rod pattern exchange. Later on December 8, power was further reduced to less than 25% in order to comply with core thermal limits Technical Specification (TS) requirements (see section 2.5). Return to 100% power was achieved on December 11. The plant remained at 100% power until December 30 when power was reduced to approximately 75% to facilitate the removal if the "C" reactor feed pump from service. The pump was secured to accomplish the repair of a minor leak on a one inch line on the suction side of the pump. At the conclusion of the report period the reactor was operating at approximately 75% of rated power.

On December 6 the licensee conducted the fourth quarter combined functional emergency preparedness drill (see section 5.1).

On December 17 the licensee notified the NRC Operations Center via the Emergency Notification System (ENS) at 2:10 pm that the reactor core isolation cooling (RCIC) system had been isolated and therefore declared inoperable to accomplish maintenance on the containment isolation system. The maintenance was completed and the RCIC system was returned to service at 2:14 am on December 18. This notification was made in accordance with 10 CFR 50.72.

2.0 PLANT OPERATIONS (71707, 71710, 40500, 90712)

2.1 Plant Operations Review

The inspector observed plant operations during regular and backshift hours of the following areas:

Control Room	Fence Line
Reactor Building	(Protected Area)
Diesel Generator Building	Turbine Building
Switchgear Rooms	Screen House
Security Facilities	

Control room instruments were observed for correlation between channels, proper functioning and conformance with Technical Specifications. Alarms received in the control room were reviewed and discussed with the operators. Operator awareness and response to these conditions were reviewed. Operators were found cognizant of board and plant conditions. Control room and shift manning were compared with Technical Specification requirements. Posting and control of radiation, contamination and high radiation areas were inspected. Use of and compliance with radiation work permits and use of required personnel monitoring devices were checked. Plant housekeeping controls, including control of flammable and other hazardous materials, were observed. During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, tagout, and lifted lead and jumper logs. Inspections were performed on backshifts including November 28 - 30 and December 3, 7, 11-13, 19, 20, 21, 26, 1990. A deep backshift inspection was performed on December 7, from 10:00 pm to 10:30 pm and on December 21, 1990 from 10:00 pm to 11:30 pm.

Pre-evolution briefings were noted to be thorough with appropriate questions and answers. The operators appeared to have good knowledge of plant conditions. No unauthorized reading material was observed. Food, beverages and hard hats were kept away from control panels.

2.2 Review of Switching and Tagging Operations

The switching and tagging log was reviewed and tagging activities were inspected to verify plant equipment was controlled in accordance with the requirements of station procedure 1.4.5, "PNPS Tagging Procedure." Implementation of the requests was reviewed on a sampling basis.

2.3 Inoperable Equipment

Actions taken by plant personnel during periods when equipment was inoperable were reviewed to verify that Technical Specification (TS) limits were met, alternate surveillance testing was completed satisfactory, and equipment was properly returned to service upon completion of repairs. Specific review was completed for the reactor core isolation cooling system inoperability of December 17-18, 1990.

Control room operators maintained appropriate control of plant operations during the brief period of RCIC system inoperability this inspection period. Appropriate TS limiting conditions for operation action statements were entered and required high pressure coolant injection (HPCI) system operability verifications were completed.

2.4 Operational Safety Findings

With the exception of the occurrences of onsite personnel failure to adhere to radiological protection procedures detailed in section 3.0, plant activities were observed to be in accordance with established procedural requirements. Licensee administrative control of off-normal system configurations by use of temporary modifications and tagging procedures was in compliance with procedural instructions and was consistent with plant safety. Overall plant cleanliness and material condition continued to be acceptable.

2.5 Reduction of Reactor Power to Less than 25%

The licensee reduced reactor power on December 8, 1990 to backwash the main condenser, conduct repair of minor condenser bay area system leaks, and to perform a control rod pattern exchange. A considerable amount of time was required at reduced power to facilitate the condenser backwash and condenser bay area leak repairs. This time period allowed reactor fuel fission product poisons to build up in the reactor. At approximately 8:00 p.m. on December 8, 1990, the P-1 plant process computer program indicated that the maximum fraction of limiting power density (MFLPD) was greater than the fraction of rated power (FRP). The licensee attempted to adjust downward the average power range monitors (APRMs) per plant procedure 8.M.1-4.2 but was unsuccessful. Reactor power was subsequently reduced to less than 25% power in accordance with Technical Specifications requirements. After reactor power was reduced, the station reactor engineering department provided the plant operators with control rod patterns to allow reactor power ascension with proper FRP/MFLPD relationships.

The licensee commenced power ascension on December 9, 1990 and achieved 100% power on December 11, 1990.

The licensee conducted a meeting on December 12, 1990 to discuss the reasons for the noted inability to adjust the APRMs per procedure 8.M.1-4.2 and any other identified concerns. The attendees at the meeting recommended that a temporary plant procedure be developed to bypass an APRM and complete the checkout of plant procedure 8.M.1-4.2. Also discussed was the feasibility of installing a new traversing in-core probe (TIP) system as a future plant modification to aid the operators in LPRM calibration, consideration of the need for revision of existing plant procedures to add alternative options other than control rod movement to clear MFLPD problems.

The licensee actions in response to the above plant conditions were correct and performed well with appropriate consideration of regulatory requirements, technical judgement and overall plant safety. No deficiencies were noted.

2.6 "B" Recirculation Pump Seal Degradation

Beginning December 25, 1990, control room operators observed that unidentified leakage had slowly trended upward from the previous 0.5 gpm to 1.5 gpm over the course of 24 hours. Concurrently, identified leakage decreased by a corresponding 1.0 gpm from 1.7 gpm to 0.7 gpm and the "B" recirculation pump #2 seal pressure was also observed to have decreased from normal pressure of 550 psi to 60 psi. Failure or degradation of the #2 seal of the "B" recirculation pump was immediately suspected. It was postulated that the shaft leakage normally collected in the equipment drain sump was leaking past the seal into the drywell and ultimately into the drywell floor sump. Leakage to the equipment drain sump is considered identified leakage and leakage to the drywell floor sump is considered unidentified leakage. The observed leakage conditions were well below Technical Specification limits of 5.0 gpm unidentified leakage and 25 gpm identified leakage.

The licensee immediately increased monitoring of the seal pressures as well as performing leakage calculations. All monitored conditions remained essentially constant through the conclusion of the report period. Additionally, the licensee developed contingency planning to provide controlled plant shutdown and seal replacement if the observed plant parameters degraded further. With respect to leakage monitoring, the licensee issued a standing order to initiate an orderly plant shutdown if the unidentified leakage rate increased to 3.5 gpm.

The licensee response to the indication of recirculation pump seal degradation to date has been well coordinated and conservative. The inspector will continue to monitor pump seal performance during routine inspection activities.

3.0 RADIOLOGICAL CONTROLS (71707)

During this inspection period the licensee identified three occurrences in which onsite personnel failed to adhere to established radiological controls procedural requirements. Each occurrence is documented below. Enforcement discretion guidance provided within the NRC Enforcement Policy is not applicable to these occurrences due to the issuance of a similar violation in NRC Inspection Report 50-293/89-10.

Procedure 6.1-022, "Issue, Use, and Termination of Radiation Work Permits," Revision 27 establishes the conditions requiring an RWP and provides guidance on its issuance and use. With specific respect to the examples below, the procedure requires an RWP be issued for entry into High Radiation Areas (areas having whole body radiation levels of 100 mRem/hour but less than 1000 mRem/hour) and areas having airborne radioactivity concentrations of greater than or equal to 0.21 maximum permissible concentration (MPC) beta-gamma activity. The procedure requires that, for entry into a High Radiation Area, personnel be briefed on the RWP and be accompanied by a radiation monitoring device (dosimetry) which continuously indicates the radiation dose rate in the area. Additionally, as a precaution and limitation, the procedure states that it is the responsibility of the individual to follow the instructions of an RWP and to be aware of radiological conditions in the area.

3.1 Failure of a Vendor Technician to Wear Issued Dosimetry

On November 30, 1990, the licensee, with vendor support, isolated a minor leak on the C reactor feed pump minimum flow line valve, FV-3437. The isolation was accomplished by several applications of a temporary leak seal process. The affected valve is located in the condenser bay which is a posted High Radiation Area and is administratively controlled as locked-closed.

The licensee established appropriate radiological controls to provide for the safe conduct of the repair activity, including issuance of a radiation work permit, pre-activity briefings, issuance of dosimetry, and remote health physics coverage (via closed circuit television). The repair crews completed two condenser bay entries and leak seal applications properly. Since these efforts failed to fully isolate the leak, a third condenser bay entry was then executed following a health physics briefing that included current dosimetry readings and reviews of accumulated worker exposures. However, after dressing into anti-contamination clothing, one vendor technician failed to don the previously issued dosimetry and accessed the condenser bay without any personnel dosimetry. The individual worked within the condenser bay for approximately forty-five minutes before it was discovered that he was not wearing the required dosimetry. Upon discovery, the individual immediately exited the condenser bay and reported to the health physics office.

The licensee initiated a Level 1 Radiological Occurrence Report to document the event. The licensee also completed an Exposure Evaluation Report to establish and assign an appropriate personnel dose exposure to the individual. A co-worker, who was in close proximity to the individual for the duration of the evolution and who was properly wearing the required dosimetry, received 80 mRem exposure during the condenser bay entry and work. This exposure was also assigned to the individual who had failed to wear dosimetry into the condenser bay area. Additionally, the licensee convened a critique to identify potential programmatic weaknesses which may have contributed to this occurrence. At the conclusion of this inspection report period, the critique report had not been issued.

The failure of the vendor technician to wear the required dosimetry into the posted High Radiation Area condenser bay is a violation of the requirements of procedure 6.1-022. This occurrence is identified as an example of the violation for failure of onsite personnel to adhere to approved radiological protection procedures as required by TS 6.11 (50-293/90-25-01).

3.2 Operator Crossed Radiation Area Boundaries Without Appropriate Authorization

On December 18, 1990, temporary radiological controls were established adjacent to the radwaste truck lock outer door to facilitate the transfer of a sludge liner which had contact readings of up to 100 Rem/Hr. The radiological controls included the establishment of a High Radiation Area within a bounding Radiation Area. The areas were properly delineated and sectioned by rope and the appropriate postings were present. The Radiation Area posting required health physics personnel to be contacted and self indicating dosimetry (SID) and TLD dosimetry to be worn prior to entry. The High Radiation Area posting required an RWP and associated controls to be observed prior to entry.

After radiological controls were established and before the sludge liner transfer evolution was initiated, health physics personnel observed a nuclear plant reactor equipment operator (NPREO) cross both the Radiation Area and High Radiation Area boundaries without observing the posting requirements, and without the required dosimetry. Because the sludge liner transfer had not begun, the dose rates in areas the NPREO traversed were essentially less than 0.2 mRem/Hr and the event posed no actual personnel radiological safety incident.

Notwithstanding the fact that no overexposure occurred, the potential for personnel exposure existed had this event occurred during the sludge liner transfer. Therefore, the licensee took immediate responsive actions. A Level 1 Radiological Occurrence Report was initiated to document the occurrence. A critique meeting was also convened to better understand the circumstances which led to the occurrence. Although the critique report was not issued prior to the conclusion of this inspection report period, it appeared the root cause of this occurrence was inattention to radiological protection postings and requirements on the part of the NPREO. As an immediate corrective action the NPREO was required to review the basis for radiological controls and postings and to brief control room operations shifts of this review during shift turnovers.

Notwithstanding the negligible safety significance of this occurrence, the failure of the NPREO to be aware of radiological controls in the area and to adhere to radiation area postings is a violation of the requirements of procedure 6.1-022. This occurrence is identified as a second example of the violation for the failure of onsite personnel to adhere to approved radiological protection procedures as required by TS 6.11 (50-293/90-25-01).

3.3 Firewatch Noble Gas Contamination

On December 20, 1990, a contracted firewatch individual received noble gas contamination after entering the augmented off gas building without observing the radiological protection posting. This posting had recently been changed to an "Airborne Contamination - RWP required for Entry." The firewatch contamination was identified when the individual alarmed the Radiological Controlled Area (RCA) exit portal monitors. The individual was immediately frisked by onshift health physics personnel with a hand held detector with the results indicating that activity levels were less than 100 cpm above background. The contamination presented negligible safety significance. Following a twenty minute delay time the firewatch worker successfully cleared two successive portal monitors, as required, prior to exiting the RCA.

Approximately two hours before the firewatch entry into the AOG building a beta aerosol monitor was observed to be alarming in the AOG building. Radiological protection personnel responded to the AOG building to verify the alarm and to collect an air sample. The air sample results indicated noble gas samples at approximately 3.0 MPC and the AOG was posted as an "Airborne Contamination - RWP Required for Entry" area. In accordance with procedure 6.1-022 such a posting is required at air samples greater than 0.21 MPC.

The licensee initiated a Level 2 ROR to document this occurrence and conducted a critique to investigate potential contributing circumstances. Although the critique report was not issued at the conclusion of this inspection period, it appears that the firewatch failed to observe the recently revised posting requirements when entering the AOG building. Several human factors elements appeared to impact this occurrence. The posting was located on the outside face of the door that the firewatch was attempting to access. It appears the individual's attention was divided between opening the door and observing the posting. Once the door was opened providing access to the AOG building the posting was no longer visible to the firewatch. Additionally, the revision to the posting, although appropriate in detail, was not easily discernable from the previous posting.

The failure of the firewatch worker to adhere to radiological controls posting requirements prior to entering the AOG building is a violation of the requirements of procedure 6.1-022. This occurrence is identified as the third example of the violation for the failure of onsite personnel to adhere to approved radiological protection procedures as required by TS 6.11 (50-293/90-25-01).

4.0 MAINTENANCE AND SURVEILLANCE (37828, 61726, 62703, 93702)

4.1 Fire Dampers and Wall Penetration Found Degraded in the Intake Structure

On November 9, 1990 at 4:30 p.m., during a maintenance team inspection plant tour, a four inch drain line check valve (scupper) was found corroded in the open position, instead of the normally closed position. The valve is located on the east wall of the "B" train salt service water (SSW) pump room. The open drain line represented a breach in the fire barrier established by the wall.

The licensee conducted followup inspections of other fire barriers in the intake structure on November 10, 1990 and five fire dampers were also found in a degraded condition, which prevented the dampers from closing, thereby rendering them inoperable. The licensee immediately posted fire watches in the affected safety-related areas which are planned to remain in effect until the fire dampers are restored to operational status. The licensee provided written report of this event in LER 90-19 (Section 7.1). The cause for the drain check valve being corroded was due to the harsh marine environment in the intake structure. This particular drain check valve was found not to have a fire protection engineering evaluation (FPEE) which is used by the station to demonstrate compliance with 10 CFR 50 Appendix R, fire protection program. Previously, an assumption was made at the time of a system walkdown that the drain line was capped at the other end, which would have been an acceptable penetration seal. Following the MTI observations, an FPEE was completed by the engineering department which determined that workable drain check valves are an acceptable fire barrier.

The fire dampers in the intake structure failed to close due to degraded and broken damper springs. The fire damper springs that were found broken appear to be caused by intergranular chloride stress corrosion. The material used in the springs was not suitable for the environment present in the intake structure. The fire damper manufacturer is evaluating the problem and will provide fire dampers that are designed to be more corrosion resistant for this particular salt air climate. The licensee's immediate corrective actions appeared to be adequate.

4.2 Emergency Diesel Generator Surveillance

The inspector observed operations department personnel performance of procedure 8.9.1, "Emergency Diesel Generator Surveillance, for the "B" Emergency Diesel Generator in both the Control Room and in the "B" Emergency Diesel Generator Room."

Each emergency diesel generator (EDG) is tested monthly to verify the ability to start within prescribed technical specification limits; to verify the EDG voltage and speed varies on demand; to verify that the EDG can synchronize with the emergency busses satisfactory; and to verify that the EDG operates at rated load for a minimum of one hour with no sign of abnormal operation. The testing also verifies that the EDG crankcase oil level is satisfactory; that the EDG fuel oil transfer pump operates satisfactory, and that the EDG starting air compressor starts and stops automatically to maintain starting air receiver pressure within prescribed limits.

Actual testing of the "B" EDG was generally orderly and all required data was recorded at both locations. However, it was observed by the inspector that the "B" EDG kilovolt-amperes reactive (KVAR) were difficult to maintain at the prescribed limits of the procedural steps by manipulation of the voltage regulator set point adjuster on the electrical control panel. The "B" EDG had also exhibited this problem in February 1990. The licensee, upon questioning by the inspector, responded that the "B" EDG only oscillated when at low KVAR and in parallel with another source of electrical power. The emergency diesel generator did not exhibit instability at greater than 2000 KW. The oscillations appear to be a repetition of the earlier observed oscillations. The licensee changed out the voltage regulator at that time which resolved the previous oscillation problem. Licensee resolution of this oscillation problem will be reviewed in future inspection reports and is considered an unresolved item 50-293/90-25-02.

4.3 RCIC Pump and Valve Operability Surveillance Testing

The inspector observed completion and close-out of the monthly surveillance testing of the reactor core isolation cooling (RCIC) system intended to comply with the requirements of Technical Specification 4.5.D.1.b and c. Procedure nos. 8.5.5.1 and 8.5.5.4 were reviewed, as were the test result records for the RCIC pump run and valve stroking and timing exercises on December 20, 1990. The inspector verified that the acceptance criteria were met, that independent verification of the appropriate test steps and final valve positions was initialed, and that the acceptance verification and signoff of the test performance were documented. The main control board position indication for ten RCIC system valves was noted by the inspector after final completion of the testing and compared with both the normal valve lineup, delineated on the RCIC piping and instrumentation drawing, P&ID M245, and also the final valve positions specified in procedure nos. 8.5.5.1 and 8.5.5.4.

The inspector noted that the stroke timing of the RCIC steam admission valve, MO-1301-61, was not documented in the test results for the monthly motor operated valve operability tests. This omission is allowed by procedure no. 8.5.5.4 because the opening time for this valve is timed and recorded during the start of the RCIC turbine in procedure no. 8.5.5.1. However, the inspector questioned why valve MO-1301-61 was not similarly stroke timed in the closed direction since the valve is designed to close on high reactor vessel water level. While stroke timing of this valve, along with several other valves governed by inservice testing (IST) requirements, is conducted in both the opening and closing directions quarterly, such a surveillance frequency would not meet the monthly test requirement for motor operated valve operability, as specified in Technical Specification 4.5.D.1.c.

The issue of whether stroke time testing of the RCIC steam admission valve in the closed direction is required to be performed monthly in accordance with the technical specification surveillance requirements was discussed with operations management personnel. An Engineering Service Request (ESR) no. 91-044 was initiated to evaluate the closing function of valve MO-1301-61 and to determine whether valve operability was contingent upon such closure testing or timing. The inspector reviewed the ESR Response Memorandum (ERM) no. 91-34, which concluded that the closing function of valve MO-1301-61 is neither a safety function, nor an action required to prevent damage to the RCIC turbine or mitigate the consequence of a RCIC system malfunction. Thus, valve operability is not dependent upon stroke timing the valve in the closed direction. The inspector had no further questions regarding the conduct of the RCIC pump and valve operability surveillance testing.

4.4 Recirculation Pump Seal Replacement Training

The inspectors witnessed a portion of a training session presented to the maintenance mechanics in the PNPS offsite maintenance training facility. This training was conducted utilizing a realistic mockup of the reactor coolant system recirculation pump seal cartridge and procedure no. 3.M.4-55 to demonstrate the seal cartridge removal from the recirculation pump, disassembly, maintenance, and reassembly in the pump. Based upon the discovery by the licensee during this inspection period of the "B" recirculation pump no. 2 seal failure (see section 2.6 of this report), the "B" pump seal cartridge will be removed and repaired during the upcoming refueling outage (RFO-8).

The inspectors monitored the conduct of training through the seal cartridge disassembly stage. The applicable maintenance procedure (No. 3.M.4-55) was used not only to follow the steps that will be utilized during the actual field work, but also to troubleshoot the procedure for directional enhancement. The seal cartridge mockup represented an excellent training aid with which maintenance activities could be mimicked. The inspectors were informed that an enclosure assembly, further mimicking the restrictive access to the recirculation pump was being fabricated to improve the realistic nature of future training on the activity.

The preparation was considered a good initiative.

5.0 EMERGENCY PREPAREDNESS (40500)

5.1 Combined Functional Drill

On December 6, 1990 the licensee conducted the fourth quarter combined functional drill (90-09) to assess the Emergency Response Organization (ERO) readiness to implement the Emergency Plan and its implementing procedures, as well as, activate and staff selected emergency facilities. Facilities activated included the Technical Support Center (TSC), Operations Support Center (OSC), Emergency Operations Facility (EOF), Technical Assessment Group (TAG), Media Center, and Corporate Information Coordinator (CIC).

The drill included the conduct of the PNPS semi-annual health physics drill and staff augmentation drill. Additionally, a site evacuation and accountability were conducted as an objective of the drill.

The licensee critique of performance during the drill determined that requisite objectives were satisfactorily demonstrated. The critique identified the following areas for improvement.

-- The addition of a dosimetry clerk to the TSC staff to access the Radiological Information Management System (RIMS).

-- Improved OSC Controller training to better track reentry team exposure.

-- Improve drill communications formality by ensuring that "This Is A Drill" prefaces all drill communiques.

Inspector review determined that the drill effectively demonstrated the licensee ability to implement and activate the challenged EP procedures and facilities. Additionally, the inspector verified that all drill critique areas for improvement were properly tracked to ensure closure accountability. The inspector had no unresolved questions regarding this drill.

6.0 **SECURITY** (71707)

6.1 **Observations of Physical Security**

Selected aspects of plant physical security were reviewed during regular and backshift hours to verify that controls were in accordance with the security plan and approved procedures. This review included the following security measures; security officer staffing, vital and protected area barrier integrity, maintenance of isolation zones, and implementation of access control including access authorization and badge issue, searches of personnel, packages and vehicles, and escorting of visitors. No discrepancies were noted.

6.2 **Security Program Audit by Licensee Quality Assurance Department**

An annual audit of the security program was conducted by the Quality Assurance Department during the period of September 17 to October 23, 1990 and the results are documented in QA audit report 90-28. The purpose of the audit was to evaluate the licensee security program and the Fitness For Duty (FFD) program for compliance to regulatory requirements and nuclear organization procedures. There were no deficiencies identified as a result of this audit. However a security deficiency report (SDR 90-261) was issued to address a weakness identified by a challenge to the Intrusion Detection System. Appropriate compensatory measures were taken to address the problems until the proper evaluations were made and corrective actions taken to resolve the weakness.

Several observations were noted by the QA auditors regarding security and FFD program procedures and practices which require management attention. Management control of contractor personnel was considered as a licensee strength by the audit team. Overall the audit team determined that the security and Fitness for Duty programs were being effectively implemented at Pilgrim station.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (92701)

7.1 LER 90-19

LER 90-19, "Fire Dampers and Penetration Found Degraded in the Intake Structure," addresses the discovery on November 9, 1990 at 1630 hours that the east wall of the "B" train salt service water pump room in the intake structure was breached. The breach consisted of a four (4) inch drain check valve (scupper) that was found corroded in the open position during an inspection by the NRC Maintenance Inspection Team. Additionally, on November 10, 1990 at 1520 hours the licensee identified, during inspection of other fire barriers in the intake structure, that six fire dampers were found with damaged closing springs rendering these fire dampers inoperable. Additionally, the LER appropriately identifies similar occurrences related to fire barrier degradation as reported in LERs 50-293/84-007-01, 85-034-00, 86-020-01 and 87-020-00. The apparent cause of the breached fire barrier and damaged fire damper springs was the marine environment in the area. This event is described in detail in section 4.1 of this report. The LER was well developed and fulfilled the reporting criteria.

8.0 ENGINEERING AND TECHNICAL SUPPORT (71707)

During various plant inspection tours and plant status checks in the control room, the inspector noted certain component installation details and system conditions which related to previous plant modifications. Where the inspector had questions regarding either the scope or engineering justification for the observed modifications, the plant design change (PDC) and design specification documents were reviewed in greater detail to ensure the adequate consideration of field conditions in the design change scope and approval.

8.1 RHR Head Spray Line Hydrodynamic Transient Analysis

The inspector conducted a review of PDC 86-20 relative to the cutting and capping of the residual heat removal (RHR) head spray pipe line. Since this design change involved retention of the portion of the piping penetrating the primary containment boundary, the inspector verified that the limiting conditions for operation were being maintained with respect to the containment isolation valves on this pipe line and in accordance with the requirements of Technical Specification 3.7.A.2.b. The review of PDC 86-20 included an examination of the affected isometric drawing details and an assessment of both the safety evaluation and the operability determination. Where the technical basis for the licensee approval was provided by contractor reports and analyses, the inspector reviewed these documents to the extent necessary to ensure the consistency of the design methodology and calculations with the final conclusion and approval.

One such contractor report, provided by the Impell Corporation, recommended that the piping and supports remaining in place in the plant after cutting and capping of the RHR head spray line be further evaluated by an appropriate hydrodynamic transient analysis. Since the impact of the water hammer event, which had occurred in this pipe line, was difficult to quantify and assess relative to the long term structural integrity of the remaining piping, operability of the containment isolation function of this piping and its valves would be verified by the results of any such transient analysis. However the inspector found no documentation within the PDC 86-20 package to indicate that such an analysis was performed. Subsequent discussion with the cognizant BECo engineer revealed that the subject hydrodynamic forcing functions and analysis had been performed by another contractor, Cygna. The inspector reviewed additional documentation from Cygna and Impell Corporation providing evidence that the proper operability assessments had been performed and that the calculation results revealed no unacceptable residual stresses remained in the piping which was still required to maintain a containment isolation capability. The inspector had no further questions on PDC 86-20 and its implementation.

8.2 Masonry Block Wall Sleeve Anchor Analysis

Another engineering issue evaluated during this inspection was the control and use of Hilti sleeve anchors for component supports in masonry block walls. The inspector had noted that such usage was common in several areas of the plant (e.g., salt service water pump bays) for safety-related component attachments. The inspector reviewed Pilgrim Specification No. C-109-ER-Q-E4 and certain referenced Hilti catalog information and test result data. No discrepancies between the installation details and the specification requirements were identified; however, certain questions were raised relative to the comparable use of Hilti sleeve anchors in masonry block walls utilizing the design loading data applicable to testing in concrete with a 2000 psi compressive strength. Also, the inspector questioned whether the mortar joints between the individual masonry blocks had been considered in assessing the impact on each anchor's shear cone of influence within the block wall matrix.

The inspector discussed these questions with a BECo structural engineer and was subsequently provided the documented basis for the engineering judgement which addressed these specific issues. The inspector noted that some of the installation details prescribed in Pilgrim civil specification C-109-ER-Q-E4 were formulated using the Hilti published allowable loading data in conjunction with conservative extrapolation of this data to masonry block applications at PNPS. The inspector evaluated the assumptions and engineering judgement upon which these extrapolations were based and determined that the technical validity of the licensee approach and conclusions was sound. The inspector had no further questions regarding the installation practices for Hilti sleeve anchors in masonry block walls at PNPS.

8.3 Followup of Previously Identified Items

8.3.1 (Closed) Unresolved Item (87-10-01), Improvements in the Snubber Visual Surveillance Program

The inspector reviewed Engineering Service Request (ESR) nos. 87-069 and 87-088, and their applicable disposition documents (NED Memo 84-944, ESR Response Memo 87-121, and various nonconformance reports, as closed) to determine what action had been taken with respect to each of the individual snubber visual inspection findings. The inspector also confirmed that hydraulic snubber testing had been successfully completed in accordance with Technical Specification 4.6.I, as specified on Maintenance Request (MR) 86-55-6 and witnessed by licensee quality control personnel. Procedure 3.M.4-28 and 3.M.4-37 were reviewed to determine whether the appropriate revisions had been implemented to clarify technical provisions that might be otherwise open to interpretation. The conduct of nuclear mechanic post qualification training in the specialized duty area of snubber work was verified and retraining of maintenance mechanics utilizing instructional modules for procedures 3.M.4-28 and 37 was noted to be part of the maintenance department training plan.

While it appears that the licensee has initiated several procedure and program revisions and enhancements since 1987 to upgrade the conduct and control of the snubber inspection program, certain technical issues remained to be resolved. One issue, identified by the inspector, involved certain provisions of procedure 3.M.4-28 (revision 19). As written, an incorrect interpretation of Technical Specification 4.6.I.1.B could allow subsequent snubber visual inspection intervals to remain at an 18 month periodicity despite the identification of a number of inoperable snubbers. While the interpretive nature of the current procedure requirement has not yet resulted in any actual problems or technical specification violations, the inspector noted that the corrective action response to a Deficiency Report (DR 1896) documented an incorrect clarification of how Technical Specification 4.6.I.1.B.3 should be applied in this regard.

Discussion of this issue with BECo compliance personnel resulted in a commitment to revise procedure 3.M.4-28 to further clarify the application of the Technical Specification provisions, as they relate to the need for increased snubber visual inspection intervals, where required. Furthermore, another Technical Specification provision (i.e., 4.6.I.2.C.1) relative to increases in the measured drag forces recorded during sequential mechanical snubber functional tests was appropriately dispositioned by the corrective action taken in the response to DR 1896. This deficiency report documented a licensee identified violation of Technical Specification 3.6.I in that an inoperable snubber was improperly reinstalled in the plant without repair. Recurrence of such a problem is precluded by licensee action which prevents any "accept-as-is" disposition to a NCR written because a mechanical snubber drag force, as tested, has increased more than 50% since its last functional test.

Notwithstanding the above examples (a licensee identified problem documented in DR 1896 and the need for a clarification in procedure 3.M.4-28 to ensure compliance with technical surveillance visual inspection intervals) the overall implementation of snubber surveillance program appears to be working effectively. The inspector selected a sample of snubbers to check for testing, repair or replacement as required, and service life monitoring. The BECo tracking system accurately accounted for each snubber's installed location by serial number, test date and results, and service life.

The inspector also examined a sample of maintenance requests relating to snubber testing and replacement and identified no problems with the implemented program of controls. No additional questions or concerns were identified in this area.

This unresolved item is considered closed.

8.3.2 **(Closed) Unresolved Item (88-33-01), Automatic Emergency Core Cooling System Load Sequencing of Diesel and Shutdown Transformers with Simulated Loss-of-Offsite Power**

This issue dealt with inconsistencies in the required starting times for the emergency diesel generators (EDG), as such times were listed in the FSAR and in the surveillance test procedures.

The Engineering Service Request (ESR) no. 88-822, initiated by the licensee to resolve these inconsistencies, was reviewed by the inspector. The licensee safety evaluation included justification for specific EDG output breaker relay time delays and recommended that the EDG surveillance procedures be revised to reflect the specified timing criteria. NRC review of the licensee's safety evaluation was documented in inspection report 50-293/89-07, in which the status of this unresolved item was updated. Although it was determined at that time that the licensee actions on this issue had addressed the NRC concerns, this item remained open pending revision of affected procedures.

During this inspection, the following documents were reviewed to verify that the licensee had established the correct and consistent EDG starting time criteria in the various engineering documents and affected procedures:

-- PNPS Final Safety Analysis Report (FSAR), section 8.5.3

-- BECo ESR Response Memorandum (ERM) 88-1072

-- PNPS Technical Specifications 4.9.A.1.a & b

-- PNPS procedure nos. 8.9.1 and 8.M.3-1, specifying EDG surveillance testing and relay timing acceptance criteria

-- PNPS schematic diagram E40 & relay settings E5-200, sheets 2 & 6

Design criteria relative to the EDG starting times, use of time delay relays, and the assumed time limits based upon accident analyses are discussed in the PNPS FSAR. The inspector reviewed this information and evaluated the translation of such design basis data into procedure, drawing and surveillance acceptance test criteria. The current PNPS design documents and operational test procedures for the emergency diesel generator reflect electrical output breaker closure times and relay setpoints consistent with both accident analysis assumptions and load connection preferences. The procedural discrepancies in the EDG starting times were corrected with procedural revisions. The inspector evaluated these changes and determined that they properly reflected a consideration of instrument setpoint tolerances without casting any doubt as to the validity of prior test results. The licensee actions to clarify and document the bounding design criteria, as well as address the NRC concerns identified in this unresolved item were deemed to be both appropriate and acceptable.

The inspector has no further questions on this issue and considers this item to be closed.

9.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30703)

9.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and areas of concern to the inspectors. On January 11, 1991 the resident inspector staff conducted an exit meeting with BECo management summarizing inspection activity and findings for this report period. No proprietary information was identified as being included in the report.

9.2 Management Meeting

On December 20, 1990, Mr. George Davis, Senior Vice President-Nuclear and Mr. Ed Wagner, Vice President Nuclear Engineering met with members of the NRC Region I staff at King of Prussia, Pennsylvania. The purpose of the meeting was to discuss items of mutual interest at PNPS and to provide an opportunity for BECo executives to meet with NRC Regional managers. A meeting summary was issued in NRC letter dated December 26, 1990.

9.3 Other NRC Activities

During the weeks of November 26-December 28, 1990, Ms. Amy Almond, an NRC Intern from the Office of NRR, was temporarily assigned to the resident inspector office at PNPS. Ms. Almond observed all aspects of routine plant operations, surveillance, and maintenance activities during her assignment. Ms. Almond also observed the administration of NRC examinations to licensee reactor and senior reactor operator candidates as well as the licensee conduct of the fourth quarter combined functional drill. Ms. Almond attended licensee plan of the day meetings, operations review committee meetings, and NRC entrance and exit meetings. Additionally, Ms. Almond visited the licensee Nuclear Engineering facilities with special emphasis on ECCS systems and safety analysis processes.

During the week of November 26-30, 1990, the NRC administered examinations to licensee Reactor and Senior Reactor Operator candidates. The results of the examination process is documented in Examination Report 505-293/90-24.

During the week of December 10-14, 1990, the NRC Region I maintenance team inspection (MTI) team leader was onsite to provide routine follow-up of MTI activities (Inspection Report 50-293/90-80).