U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 94-11

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: May 10 - June 20, 1994

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Approved by: R. Conte 7/15/94
R. Conte, Chief Date
Reactor Projects Section 3A

Scope: Resident Inspector safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, and plant support. Initiatives selected for inspection included implementation of several recently approved Technical Specification safety-related instrument setpoint changes and the cutting, removal, and shipment of control rod velocity limiters from the spent fuel pool.

Inspections were performed during backshifts on May 10, 11, 13, 16-19, 23, 25, and 26, 1994 and June 2, 3, 7, 8, 13, 14, and 17, 1994. Deep backshift inspections were performed on May 14 (9:55 am - 2:50 pm), May 17, 1994 (10:00-11:55 pm), June 11, 1994 (3:25-10:00 pm), and June 12, 1994 (7:25 am - 2:35 pm).

Findings: Performance during this six week period is summarized in the Executive Summary. Licensee response to a previously issued notice of violation (NOV 50-293/92-80-01) and actions to address two previously identified unresolved items (URI 50-293/91-80-06 and URI 50-293/93-13-01) were reviewed and found appropriate to support NRC closure of these issues.

EXECUTIVE SUMMARY

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Plant Operations:

Control room operators responded effectively to the unanticipated recirculation pump motor generator (MG) set trip that occurred on June 10, 1994, during annunciator modifications. Actions were promptly taken to insert control rods to below the 80% load line and to stabilize reactor parameters. Additionally, operators quickly manually started an auxiliary oil pump to ensure proper lubrication of the affected MG set. The subsequent event critique was well attended and comprehensively addressed factual information and initial causal analysis. Recirculation pump restart was similarly well controlled and was completed satisfactorily.

Nuclear watch engineers (NWES) maintained positive control of station status during recent safety-related instrumentation setpoint changes that necessitated brief periods of safety system inoperability. Similar oversight was evident during key portions of the spent fuel pool cleanup project. Additionally, NWEs promptly addressed deficient housekeeping issues identified during the inspection period that had the potential to create contamination and personnel injury hazard.

Maintenance and Surveillance:

Excellent coordination and communications were evident during the recent safety-related instrument setpoint changes associated with the 24 month operating cycle Technical Specification Amendment. Pre-evolution briefs were thorough and the work was well planned, minimizing periods of safety system unavailability and partial instrumentation logic system completion. A conservative action was evident in the temporary resolution to a leaking high pressure coolant injection system instrument isolation valve that prevented completion of a required calibration test. An alternative calibration isolation boundary was established and appropriate NRC notification criteria were fulfilled. Separately, several instances of incomplete post maintenance work area restoration were identified in which tools and other materials were not properly removed and stowed.

Engineering:

Engineering calculations associated with the 24 month operating cycle instrument setpoint changes properly incorporated the effects of degraded voltage, normal instrument drift, vibration, and the harsh post accident radiological and climatological environment. The motor operated valve project team continues to aggressively pursue dynamic testing schedules and valve and actuator modifications to address NRC Generic Letter 89-10 concerns. The reactor core isolation cooling system oil filtration system modifications designed to resolve past speed control system fouling are good technical initiatives.

(EXECUTIVE SUMMARY CONTINUED)

Plant Support:

The ongoing spent fuel pool cleanup project continues to be conducted in a well controlled and safe manner. The recent cutting and offsite shipment of control rod velocity limiters was of particular note. Good communications and coordination were evident. Positive contamination controls and radiological and industrial personnel protection measures were established.

Safety Assessment/Quality Verification:

The Nuclear Safety Review and Audit Committee meeting convened during this report period reviewed recent significant plant activities in good detail. Questioning attitudes were apparent and good technical interaction was noted. Corrective actions and programmatic improvements were completed such that three previous potential safety problems were resolved and closed. Specifically, the problem report process has effectively consolidated deficiency identification processes and has resulted in the timely resolution of plant issues. Procedural improvements and enhanced operator training have been established to ensure adequate cooling of the switchgear and battery rooms in the event of a loss of normal plant ventilation to these areas. Finally, controls for the administration of the preventive maintenance deferral process have been improved to ensure appropriate technical and managerial reviews have been completed before a preventive maintenance activity can be deferred.

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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 May 22, 1994, a small brush fire was reported on the far south side of the new support building parking lot. The licensee made a courtesy notification to the NRC Operations Center (NRCOC) regarding the fire, which was well outside the protected area, on owner controlled property, and which had no impact on facility operations. On June 3, 1994, the high pressure coolant injection system was briefly declared inoperable to accomplish instrument calibrations. The system was returned to service later the same day following successful completion of the calibration procedure (Section 3.1). On June 6-10, 1994, the shutdown transformer and station blackout diesel generator were removed from service for planned maintenance. With the exception of brief power reductions to accomplish surveillance testing and control rod exercising, the reactor remained at full power until June 10, 1994, when the 'A' recirculation pump motor generator (MG) set inadvertently tripped during the implementation of an annunciator modification. Reactor power was stabilized at approximately 35% and the cause of the event was reviewed and evaluated (Section 2.2). The MG set was restarted and the reactor was restored to 100% power later the same day. On June 19, 1994, reactor power was decreased to perform a scheduled thermal backwash of the main condenser. The reactor was returned to 100% power later the same day and remained at full power through the end of the report period.

2.0 PLANT OPERATIONS (71707, 40500, 92701)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations (during regular and backshift hours) in 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 independently observed by NRC inspectors and found to be in correlation amongst channels, properly functioning and in conformance with Technical Specifications. Alarms received in the control room were reviewed and discussed with the operators; operators were found cognizant of control board and plant conditions. Control room and shift manning were in accordance with Technical Specification requirements. Posting and control of radiation, high radiation, and contamination areas were appropriate. Radiological postings and practices were especially well controlled during the ongoing fuel pool cleanup project. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

Plant housekeeping, including the control of flammable and other hazardous materials, was observed. The general material condition of the process buildings was good. However, the inspectors noted several instances where personnel had left unnecessary tools and debris laying loose within contaminated work areas after they had left the area. Some items had the potential to create personnel safety hazards, while others raised the potential for spread of contamination into clean areas. On several occasions, unused anti-contamination clothing was found laying loose within the process buildings. The inspectors informed the Nuclear Watch Engineer of these conditions and appropriate corrective actions were promptly initiated. 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.

2.2 Recirculation Pump Trip

On June 10, 1994, at 10:54 am, the 'A' recirculation pump motor generator (MG) set tripped as a result of a low lube oil pressure condition. Recirculation flow through the reactor core and reactor power decreased in response to the pump trip. Operators verified the trip condition, manually started the standby alternating current (AC) oil pump for the 'A' recirculation pump, and promptly initiated the actions of procedure 2.4.17, 'Recirculation Pump Trip.' Control rods were inserted to below the 80% load line. A senior reactor operator was stationed as the reactivity control manager to supervise control rod and recirculation flow manipulations and the reactor was stabilized at 35 percent power. The station operating license permits continued power operation for up to twenty-four hours with single recirculation loop out of service. The inspector verified stable plant conditions, inspected the work area where a control room annunciator design change had been in progress at the time of the pump trip, and subsequently attended a licensee critique of the event. Initial operator response and implementation of station procedures were effective in managing core reactivity and assuring stable reactor operations during the recirculation pump trip induced transient. Operators on watch at the time of the event were properly relieved to facilitate their presence at the post event critique.

Approximately twenty people attended the multi-disciplined event critique. Maintenance technicians and operators provided a detailed account of the in-progress annunciator design change work, control room indications, and plant response at the time of the recirculation pump trip. System engineers evaluated computer printouts of recirculation pump MG set performance characteristics from before, during, and after the transient. There was no evidence of repetitive problems with MG speed control problems (NRC Inspection Report No. 50-293/93-15) indicating effective corrective actions. Probing questions were asked and information was readily shared during the critique.

Independent observations confirmed that the following sequence of events occurred. The running AC oil pump (provides oil to MG bearings and to the MG fluid coupler for speed control) stopped, the standby AC oil pump failed to start as designed upon sensing low oil pressure, and the standby direct current (DC) oil pump failed to start on low oil pressure. The subsequent low lube oil pressure condition caused the 'A' recirculation pump MG set to trip.

Engineers reviewed system electrical control drawings and identified one portion of the control circuit which is common to the start/run logic of all three oil pumps. An open circuit condition at this common point would cause the running pump to stop and would prevent the standby start feature of the remaining two pumps. The inspector independently reviewed the electrical drawings and concluded that an open circuit at the common logic junction was the most probable cause of the event. Other potential logic circuit component failures were sequentially eliminated because they did not have the capability to affect all three oil pumps simultaneously. Maintenance technicians, implementing the control room annunciator design change, were working in the vicinity of the common terminal of the oil pump logic circuit at the time of the trip. The work plan directed technicians to land a new lead on terminal point 31 which controlled drawings showed to be a spare contact. However, workers found a lead from the oil pump control logic circuitry landed at this terminal. Technicians stated that they had placed a screw driver upon this terminal, but had not loosened the screw for this contact point prior to the recirculation pump trip. Interviews with the maintenance technicians could not conclusively identify a cause for or the existence of a temporary open circuit at this terminal location. Problem report (PR) 94.9253 was initiated to formalize the causal analysis for this event. The annunciator design change was temporarily suspended pending a review of the work scope and a field validation of intended work activity.

The recirculation oil pump control circuit was visually inspected and the start/standby/auto-start functions of the three oil pumps were successfully demonstrated with no problems identified. The licensee restarted the 'A' recirculation pump at 2:32 pm and restored the reactor to full power at 7:14 pm, on June 10, 1994. The inspector concluded that the licensee critique, follow-up inspections, and PR initiation were appropriately implemented in response to this event. Management oversight was deliberate throughout the event critique and assessment process and reactor core reactivity was closely controlled during the transient and restoration to full power.

3.0 MAINTENANCE AND SURVEILLANCE (61726, 62703, 71707)

3.1 High Pressure Coolant Injection System Declared Inoperable During Routine Surveillance

On June 3, 1994, the high pressure coolant injection (HPCI) system was declared inoperable during a planned calibration of the 'B' torus level instrument (LT-5038). Technical Specifications require the torus level instruments to be calibrated at least once per six months. Station procedures currently require the torus level instrument to be calibrated more frequently, at two month intervals, due to potential instrument drift. During performance of the instrument calibration procedure (8.M.2-6.5) in May 1994, technicians observed leakage past the instrument isolation valve which invalidated the calibration results. The surveillance was secured and rescheduled for later within the required calibration period. Procedure 8.M.2-6.5 was revised to use the upstream 'B' torus level instrumentation line isolation valve (1001-283) to establish the calibration test boundary. However, closing valve 1001-283 also isolates a level switch (LS-2351B) which is connected in parallel with LT-5038. The level switch provides an automatic signal which swaps the HPCI pump suction from the condensate storage tank (CST) to the torus

in the event of a high torus water level condition during HPCI operation. The revision to procedure 8.M.2-6.5 recognized this condition and specifically stated that closure of 1001-283 would defeat the HPCI CST/torus suction swap, which in turn would cause the HPCI system to be technically inoperable.

The licensee declared the system inoperable when the revised procedure was performed and the automatic HPCI suction swap-over feature was defeated. The NRC Operations Center was properly notified in accordance with the requirements of 10 CFR 50.72. The HPCI system remained available for automatic initiation if called upon. The Nuclear Operations Supervisor properly briefed control room operators regarding the need to manually shift the HPCI suction if a high torus water level condition developed while LS-2351B was isolated. The inspector discussed the calibration procedure with the instrumentation and controls job supervisor who demonstrated a high level of knowledge regarding the work to be performed and the impact of isolating LS-2351B. The time during which 1001-283 was closed was effectively minimized. The calibration of LT-5038 was successfully completed in approximately three hours and the HPCI system was declared operable. The inspector observed that the licensee decision to declare HPCI inoperable in light of the controlled procedure revision and contingency planning to manually swap the HPCI pump suction was conservative.

The inspector questioned why repair of the LT-5038 root valve was not performed while 1001-283 was shut to support the instrument calibration. The Operations Section Manager stated that potential for draining the torus during the repair, although small, outweighed the importance of the short term loss of the auto-swap over feature for the HPCI pump suction. The torus level instrument calibration is due to be performed one more time prior to the scheduled mid-cycle maintenance outage. The inspector verified that repair of the LT-5038 instrument root valve is included on the list of planned maintenance in the event of a forced plant outage. The licensee is currently reviewing the issue of whether calibration of LT-5038 using the revised procedure 8.M.2-6.5 places HPCI in an inoperable condition. The inspector considered licensee actions in response to the leaking instrument root valve to be reasonable and considered the decision to schedule the valve repair during an outage, in lieu of on-line, to be prudent.

3.2 Implementation of Technical Specification Setpoint Changes

Technical Specification (TS) Amendment No. 151 revised several safety-related protective instrument setpoints to support extension of the reactor operating cycle from eighteen months to twenty-four months. During this report period, the licensee implemented five of the Instrumentation and Control (I&C) setpoint changes in accordance with plant design change (PDC) 94-05. Each of the five setpoint changes was performed with the reactor at power. The inspector reviewed two of the setpoint changes in detail to verify proper calibration setpoint adjustment, work controls, procedure revision, and TS operating actions as required.

The inspector reviewed the basis for the containment spray permissive and the HPCI low pressure isolation setpoint revisions (Engineering calculation No. I-N1-94, 133, and 153). Containment spray is used to reduce containment pressure during certain accident scenarios.

Permissive logic automatically secures spray flow and redirects cooling water to the reactor vessel to maintain two-thirds core coverage. The containment spray permissive setpoint (reactor vessel water level below which containment spray is redirected to the reactor vessel for core coverage) was raised in the conservative direction by 24.5 inches. The revised setpoint accounts for instrument response during a design basis accident, including the effects of degraded voltage, elevated radiation, temperature, humidity, and vibration, as well as normal instrumentation drift associated with the extended surveillance intervals. The HPCI isolation on low reactor pressure secures HPCI and minimizes the release of radioactive gasses to the reactor building when steam pressure is no longer sufficient to operate the HPCI turbine. The inspector concluded that engineering design setpoint calculations were detailed and properly accounted for design variables. Vendor specifications and system performance history for the past five years were closely evaluated to accurately determine anticipated transmitter and trip unit instrument drift characteristics. The TS setpoints were developed consistent with the guidance of NRC Regulatory Guide 1.105, 'Instrument Setpoints for Safety-Related Systems.'

Maintenance technicians implemented the containment spray permissive and high pressure coolant injection (HPCI) system isolation setpoint revisions in accordance with procedure 8.M.1-32.6, 'Analog Trip System/Trip Unit Calibration/Cabinet C2233A, Section B.' The inspector reviewed the recently revised procedure and discussed implementation with maintenance and operations personnel. The inspector determined that the procedure had been properly revised, reviewed, and approved. Both maintenance and operations personnel were aware that the TS instruments and their corresponding systems would be temporarily inoperable during the period of time needed to perform the calibration setpoint change. The evolution was thoroughly prebriefed including required TS actions during the period that the instruments would be inoperable. Technicians performed the setpoint change and calibration promptly and demonstrated detailed knowledge of the procedure. Operators entered and exited appropriate TS required action statements in a timely manner. The inspector concluded that the TS setpoint change was implemented in a safe and controlled manner.

The inspector noted that the revised reactor vessel water level instrument calibration setpoint (-150 inches) and corresponding no adjust band ($\pm$ 0.375 inches) for the containment spray permissive interlock were very close to the TS setpoint (-151 inches). The inspector questioned whether the newly established calibration setpoint value and no adjust band were sufficiently conservative with relation to the required TS value to account for instrument drift that may occur during the time interval between periodic instrument calibrations. This concern was discussed with operations and engineering staff personnel who subsequently initiated a review of instrumentation calibration setpoint to TS setpoint margins.

The system engineer reviewed the instrument calibration history and found that instrument drift over a 120 day period (90 day surveillance interval plus 25 percent allowed grace period) has historically remained less than 0.6 inches (95 percent of the time). The inspector independently quantified the instrument drift characteristics, consistent with the system engineer's findings. The licensee determined that the cumulative probability of the instrument being (1) at the low end of the no adjust band and (2) exceeding 0.6 inch drift is very low. The licensee concluded

that the existing reactor vessel level instrument calibration setpoint for the containment spray permissive interlock provided sufficient margin from the TS setpoint to avoid inadvertent TS setpoint violations. Engineers reviewed twenty additional TS instrument calibration setpoints to verify whether the margin between the newly established calibration setpoints and the respective TS setpoints were sufficient to preclude drift beyond TS limits. Engineers stated that the result of their review will be discussed with the operations staff. The inspector discussed the review process with engineers and concluded that licensee actions were appropriate and conservative to fully assess the operational impact of the newly established TS and instrument calibration setpoints.

4.0 ENGINEERING (37828, 71707, 92701)

4.1 Motor Operated Valve Upgrade Program Project Meeting

The motor operated valve (MOV) project team met on June 2, 1994 to discuss readiness to conduct MOV testing and maintenance during the upcoming mid-cycle outage (October 1994) and refueling outage (April - May 1995). The meeting was well attended by representatives from engineering, maintenance, planning, procurement, and scheduling. Topics discussed ranged from design basis review, industry 10 CFR Part 21 issues, and design changes to scheduled dynamic MOV testing, staff augmentation, training, and outage management organization structure. The inspector noted that the production schedule was closely controlled and coordination and support throughout the organization was evident. However, the planned work load for both outages is large. Continued management support and close coordination are needed to facilitate accomplishment of this aggressive maintenance work load during the currently scheduled outage durations.

The inspector observed that specific emphasis was appropriately placed on two items which currently delay outage preparations. These items are (1) contractor schedule to complete weak link analysis in support of the licensee design basis review and (2) various holdups in the review/approval process that have delayed work package planning. The team identified actions to address both of these issues. A multi-tiered training program was initiated to upgrade both craft level and supervisor knowledge of MOVs. The program incorporates detailed test equipment training conducted by the vendor, hands-on MOV rebuild training at the licensee training center, and additional supervisor and team (supervisor plus craft) test equipment training at the licensee training center. Feedback from the initial phases of the training have been very positive. The project team also indicated that the licensee is considering installation of a new valve and actuator design during the next refueling outage. The new valve design incorporates improved internal valve component clearances which are intended to reduce friction and improve the valve factor. The licensee has worked closely with various contractors to validate the design. A decision on the use of the new design is expected by July 1994. The inspector concluded that the project team was aggressively managing the work schedule and addressing potential technical and production challenges in a timely manner.

4.2 Reactor Core Isolation Cooling (RCIC) System Betterment Program Update

Previously on several occasions, the licensee has experienced difficulty maintaining desired RCIC speed control. Troubleshooting of the system indicated that speed oscillations were likely caused by mechanical failure of the speed control system hydraulic actuator (EG-R). The licensee determined that the root cause of the EG-R failure was grit in the hydraulic control oil, which caused mechanical binding and wear of the pilot plunger assembly. The manufacturer of the oil filter system (Woodward Governor Company) stated that the oil must be filtered to at least 20 microns. However, the RCIC Turbine Oil Filter System was delivered with a 38 micron filter as part of the original designed equipment.

In order to resolve this issue, the licensee has developed a comprehensive design change that addresses the filter capacity and modifies the oil sump connections to allow for external filtering and better bottom drain capability. The inspector review of the proposed design change (PDC 94-29) indicated major design improvements in the oil flow system over the original Woodward Governor Company design. To correct the oil flow and filtering problems that the licensee identified with the Woodward design, the following modifications are scheduled for the mid-cycle 10 outage to start October 1994.

- The present knife type oil filter is to be replaced with an eight micron replaceable cartridge type filter and filter housing.
- A tee with a valve and a threaded cap will be added upstream of the new filter to provide an inlet connection for an external oil circulation and cleanup system.
- An elbow oriented vertically in the downward direction will be added to one end of the oil reservoir with a drain ball valve attached to the elbow.
- A vent and oil fill connection will be added to the high point of the lube oil piping. Also seismic piping supports will be added for this design modification.
- An independent skid mounted oil filtering system will be designed or purchased to independently filter the RCIC oil during flushing of the system.

The inspector concluded these actions adequately address past oil system cleanliness concerns.

5.0 PLANT SUPPORT (71707)

Shipment of Control Rod Velocity Limiters

The licensee has actively implemented a fuel pool cleanup project over the past several months. Objectives of this project included removal of stored radioactive material (RAM) which is suitable for disposal, bottom cleanup to improve clarity and visibility, and rearrangement of stored material to support the potential future installation of additional fuel assembly storage

racks. The removal and shipment of velocity limiters from fifty-five control rods stored in the spent fuel pool was recently added to the scope of this project. The availability of off-site RAM transportation casks is currently very limited. This resulted in a relatively narrow time window for the velocity limiter removal and shipment to be accomplished.

The previously established fuel pool cleanup team developed a detailed plan to ship the velocity limiters and to mount the remaining portion of each control rod from the fuel pool walls using a specially fabricated clamp device (plant design change 94-26). The velocity limiter (VL), which contains activated stellite rollers, is a two foot long component at the bottom of each control rod. An underwater cutting device was used to detach the VL from each individual control rod in the spent fuel pool. The VLs were then segregated in one portion of the pool and the control rods were mounted into the newly installed wall-mounted clamps. The inspector attended the pre-evolution brief and observed the underwater cutting and removal of the VLs from the refueling bridge, above the spent fuel pool. The job supervisor closely monitored the evolution and directed tasks appropriately. Communications were clear, and proper radiological precautions were implemented.

The project team gathered information from other licensees who had performed similar shipments and developed four options for the transfer of the VLs from the pool to an offsite shipping container. Each option involved a two step transfer. The selected option allowed improved human factors control of the transfer, minimized personnel radiation exposure, and offered recovery capability in the event that a VL transfer could not be completed. The first step moved the VLs from the pool to an on-site storage container (OSSC) located on the refuel floor in the reactor building. The second step lowered the OSSC to ground level of the reactor building and transferred the VLs to an off-site transportation cask upon its arrival. The inspector discussed the transfer options with the project manager and independently concurred with the option selection. The inspector questioned the licensee intention to place a plastic sheet over the reactor building equipment hatch as a precautionary contamination barrier. The inspector expressed concern that the temporary barrier could alter the design reactor building ventilation flow. The inspector questioned whether the open reactor building equipment hatch was credited in the station accident analysis for prolonged operability of certain safety-related equipment in the harsh environment which may result from a high energy line break within the reactor building. The licensee initiated a review of the reactor building design ventilation flow, but determined that the issue would not be resolved prior to the scheduled VL transfer. Alternate contamination controls were subsequently developed and the reactor building equipment hatch was maintained uncovered. The inspector concluded that this action was appropriate. Use of temporary shielding, contamination barriers, demineralized water spray of VLs as they exited the pool, OSSC and recovery container positioning, and personnel task coordination were effectively integrated into the work plan.

Detailed process control work plans were developed for the two step VL transfer. The inspector attended pre-evolution briefings and observed portions of the evolution. Questions were properly resolved and job assignments were clearly identified. Work briefings by radiological protection technicians were detailed and comprehensive. A dry run walk through of the transfer evolution

was conducted with no problems encountered. Transfer of the fifty-five VLs was accomplished in a safe manner and consistent with the established schedule. Radiological considerations such as contamination control and personnel radiation exposure were effectively identified and managed throughout the evolution. The inspector noted minor areas for improvement with regard to reducing the number of workers in the vicinity of the storage containers during certain phases of the transfer. These observations were properly addressed by the project manager during a post evolution review. The project team review of the VL transfer was constructive, identifying both positive items for use in future RAM moves and some process improvements which may further reduce personnel radiation exposure. The post job review process took on added importance, since several additional RAM shipments are scheduled. The inspector concluded that the VL transfer/shipment evolution was conducted in an outstanding manner. Effective planning, coordination, and communications between radiological, maintenance, operations, and engineering personnel were key elements of the safe completion of this activity.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 92702)

6.1 Nuclear Safety Review and Audit Committee

The inspector attended portions of the most recent Nuclear Safety Review and Audit Committee (NSRAC) meeting that was convened on June 2, 1994. The committee is comprised of both licensee and non-licensee personnel, who provide independent review and audit of a wide range of Pilgrim Station activities. The NSRAC currently meets four times per year, which is more frequent than required by Technical Specifications (TS). All nine primary members of the committee were present. The committee thoroughly reviewed current operating status, reportable events since the last NSRAC meeting, ongoing issues including reactor component fatigue analysis, proposed TS change requests, and planning for future plant outages. Questions raised by committee members probed deeply into the above issues. Responses by the plant staff were frequently challenged for more in-depth information. The meeting also served as a forum for NSRAC members to share experiences from elsewhere in the nuclear industry which were germane to issues being addressed at Pilgrim Station. The inspector concluded that NSRAC effectively performed review and audit of station activities.

Mr. Robert S. Brodsky retired from the NSRAC as had been planned following the conclusion of the June 1-2 meetings. The licensee is in the process of recruiting another senior experienced industry recognized specialist to replace Mr. Brodsky. It is anticipated a selection will be made and the individual will be in place prior to the next scheduled NSRAC meeting.

6.2 Follow-up of Previously Identified Items

6.2.1 (Closed) Violation 92-80-01, Failure to Correct Controlled Motor Operated Valve Drawings in a Timely Manner

The NRC staff conducted an initial team inspection of the motor operated valve program in March 1992. The team observed that 24 torque switch setting discrepancies identified by the licensee in an April 1991 self-assessment had not been resolved. The NRC issue a Notice of

Violation to the licensee due to its failure to take timely corrective actions to resolve these issues. Subsequent diagnostic testing indicated that the valves would have been capable of performing their intended safety functions with the as-found torque switch settings.

The licensee reply to the Notice of Violation (Boston Edison Company letter 92-060, June 4, 1992) stated that the following correction would be implemented to resolve the issue of timely corrective actions:

- Initiate a single corrective action document through the problem report (PR) program that was developed to replace the Failure & Malfunction Report, Potential Condition Adverse to Quality, Recommendation For Improvement/Investigation, Radiological Occurrence Report (ROR), and in-plant non-conformance report processes.

The Problem Report Program was initiated on March 30, 1992. To support this program, the following procedures were issued:

- Procedure NOP92A1, 'Problem Report Program.' This procedure has been revised to include the various programs that were described in Boston Edison's letter, 92-60, June 4, 1992;

- Procedure NOP93A1, 'Operability Guidance.' This procedure provides guidance for evaluation of potential or actual degraded or nonconforming conditions, with respect to operability; and

- Training has been given on NRC findings 92-80-01 and Generic Letter 91-18, 'Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability.'

The inspector verified that the 'Notice' process of the Problem Report Procedure, NOP92A1, is working. This process, similar to the master surveillance tracking program (MSTP) notice process, provides automatic notification to coordinators and assigned responders when certain milestones are reached. First, the 'Alert Notice' is issued one day after the action due date. Next, a 'Priority Notice' is issued on the action's dead date. Finally, the 'Failure to Comply Notice' is issued each day after an action has passed its dead date. These reports are evaluated by plant management to ensure that prompt actions are taken.

The inspector verified that both 'Alert' and 'Failure' reports are issued and reviewed by plant management prior to their due dates. The inspector review concluded the licensee's program and controls have been implemented to ensure plant issues are identified, documented, reviewed, and corrected in a timely manner This Item is closed.

6.2.2 (Closed) Unresolved Item 91-80-06, Switchgear and Battery Room Heating, Ventilation and Air Conditioning System

During an NRC staff walkdown of the heating, ventilation, and air conditioning (HVAC) systems, the inspectors noted that no temperature monitoring indicators were installed in the switchgear and battery rooms. The inspectors noted that the rooms appeared to be very hot due to a planned outage of the HVAC system during the refueling outage. The inspectors concluded that the adequacy of the HVAC for the switchgear and battery rooms, under a postulated failure, had not been determined. The qualification of the electrical equipment, and its operation under the worst-case conditions, had not been evaluated. Additionally, no administrative controls were in place to monitor the temperature conditions of Class 1E equipment in these rooms.

The licensee established immediate compensatory measures to protect the equipment in the room until an evaluation of the temperature in the switchgear and battery rooms could be completed. The licensee initiated the following compensatory actions:

- Blocked open the outside air fan dampers so that an air supply was available if the instrument air failed;

- Connected a portable diesel generator to provide back-up power to the turbine building supply fan and roof ventilators; and

- Connected the temperature sensors in the switchgear and battery rooms to the alarms in the control room at 95°F instead of just recording the area temperatures.

Licensee Analysis NAP92-27, 'Assessment of Ventilation Operability,' indicated that once natural circulation ventilation is established, area temperatures rise slowly. Natural circulation ventilation is created by opening six doors in the turbine building. Additional operator actions to shed or transfer electrical loads would be based on plant conditions at the time. However, the analysis indicates that once natural circulation ventilation is established, the licensee has in excess of three hours to complete various operator actions. Field test data has been used in supporting the heating model that was used in the NAP92-27 analysis report. The licensee has also completed the following actions to support a loss of HVAC in the switchgear and battery rooms:

- Installed a temperature recorder (TISU-8125) set to alarm at 95 F for both rooms.

- Issued procedure 2.4.153, 'Loss of Switchgear Area Ventilation,' which provides operator actions in the event that the HVAC is lost to the switchgear and battery rooms.
    - Provided additional instruction for immediate operator actions in alarm response procedure ARP-905L, 'Alarm on Increasing Switchgear/Battery Room Temperatures.'

The inspector reviewed, with the plant operators, actions to be taken in the event of a loss of the HVAC to the switchgear and battery rooms. The operators demonstrated good knowledge of required responses and procedure implementation if this event were to occur. The inspector determined that adequate training and plant procedures are in place to support the engineering evaluation of this system. This item is closed.

6.2.3 **(Closed) Unresolved Item 93-13-01, Improper Preventive Maintenance Deferral**

In June 1993, the inspector conducted a review of the preventive maintenance (PM) deferral process after the failure of scram inlet valve diaphragm, whose planned replacement had been deferred. The review concluded the PM deferral process was not being consistently implemented.

To resolve the PM deferral process problem, the licensee included the PM program as part of the master surveillance tracking program (MSTP). Procedure No. 1.8, 'Master Surveillance Tracking Program,' describes how the deferral program functions within the MSTP system. A plant repetitive task coordinator (PRTC) is designated to review and approve all proposed changes to the MSTP data base. This individual is required to ensure that all requests for changes to the data base receive adequate reviews from a regulatory compliance and technical standpoint.

Additionally, procedure 3.M.1-1, 'Preventive and Surveillance Maintenance Requests,' has been revised to ensure that recurring tasks are included in the MSTP. The PRTC issues both an 'ALERT' and 'FAILURE' report to management, based on the data in the MSTP. These reports identify the effect that a deferral may have on a system if the scheduled PM is not performed. Thus, plant management is provided advance indication of potential problems, which allows for specific action to be taken before a required action or an intended commitment is missed.

The inspector reviewed 'Alerts' on five completed component surveillance tests. In each case, the Plant Repetitive Test Coordinator (PRTC) had informed management that a surveillance test was not performed, and passed its due date or would pass its due date if action was not taken. In each case, the inspector verified that adequate action was taken by management to ensure that the surveillance testing of the item did not go beyond its "drop dead" date. The inspector has no further questions regarding this issue, and determined that the licensee actions had addressed the inspector concern regarding PM deferrals.

The unresolved item also addressed review of the root cause determinations of the failure of the scram outlet valve diaphragm and evaluation of the diaphragm shelf life requirements. Testing of the diaphragm material including chemical composition and hardness testing was performed by the licensee. The results of the licensee analysis indicated no significant variation in the material composition of controlled diaphragm samples. The root cause investigation determined that the diaphragm failure was the result of either a manufacturing defect or damage during installation. The licensee replaced twenty-five percent of the scram inlet and outlet valve diaphragms, using Procedure 3.M.4.76. The inspector review of the scram valve maintenance

program documentation verified that a procedure change notice had been issued to procedure 3.M.4.76 to include the vendor recommended 15-year total life requirement (from date of manufacture). In addition, the inspector verified that the parts list had been updated to indicate that the scram valve diaphragm shelf life of seven years cannot be extended. The inspector concluded that the licensee actions to identify and correct the scram valve problem were appropriate. This item is closed.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES (30702)

7.1 Routine Meetings

At periodic intervals during this inspection, meetings were held with senior BECo plant management to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting on June 28, 1994, summarizing the preliminary findings of this inspection. No proprietary information was identified as being included in the report.

7.2 Other NRC Activities

On June 6-10, 1994, an NRC Region I systems engineering specialist completed the second half of an inspection of reactor code safety valves and safety relief valves. Results of this inspection will be documented in NRC Inspection Report No. 50-293/94-07.

On June 13-17, 1994, two NRC Region I operator licensing specialists conducted an inspection of the operator licensing requalification program and selected maintenance activities. Results of this inspection will be documented in NRC Inspection Report No. 50-293/94-10.